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AIR QUALITY POLICY ANALYSIS OF ELECTRIC UTILITIES: A REGIONAL PERSPECTIVE

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ARGONNE NATIONAL LABORATORY

ENERGY AND ENVIRONMENTAL SYSTEMS DIVISION

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ABSTRACT

Recently more and more concern is being expressed over the energy and environmental dilemma, particularly as it relates to air quality goals. This report presents the results of a regional assessment of environmental policy and technological options for achieving energy and environmental goals in the Midwest. Policy options considered include alternative air quality goals -- altered emission limits and delay of compliance schedules. Technological options analyzed include transport of Western low sulfur coal and utilization by Midwestern utilities, adoption of supplementary control systems for electric utilities, and use of stack gas scrubbers. The study analyzed these options in light of their economic and environmental effects.

EXECUTIVE SUMMARY

Sulfur dioxide control policies for electric utilities have been the subject of public debate and analysis since the passage of the Clean Air Act amendments requiring the development of State Implementation Plans and achievement of National Ambient Air Quality Standards. The availabilities of low sulfur coal and control technologies, in conjunction with the performance of the control technologies, have been issues of national and state concern. In recognition of these issues and the impending possibility of energy shortages, the Energy Supply and Environmental Coordination Act of 1974 was enacted. Among its many provisions, this Act required an assessment of State Implementation Plans and evaluation of the possibility of fuel savings resulting from modifications to these regulations.

This report analyzes alternative state emission limits and compliance deadlines for the Midwest in an economic and environmental context by evaluating alternative control policies in the light of both their air quality effects and economic dislocations to the electric utilities. A policy analysis tool was developed for analyzing the least-cost control response by electric utilities to alternative air quality policies. The methodology permits analysis of the cost for individual power plants of alternative methods of compliance and proceeds forward in time to allocate supplies against demand until equilibrium and compliance are achieved. The result is a regionwide, year-by-year pattern of demand, cost, and compliance. The predicted pattern of compliance over the period of study can be interpreted to assess the air quality improvements resulting from alternative policy options, as well as the variances required because of limited supplies of low sulfur fuel and control devices. Patterns of utilization of control technologies and low sulfur coal and the unsatisfied demand give a picture of the future of both the scrubber industry and of Western coal production under various policy assumptions. Costs incurred by the utilities in order to comply with various air quality regulations permit a cost-effectiveness analysis of potential policies.

A data base is developed for the time period of 1975 through the early 1980s, and policies are analyzed over this time frame. The analysis is conducted for five Midwestern states: Ohio, Indiana, Illinois, Wisconsin, and Michigan. The low sulfur Western coal analysis includes estimates of the production, transportation, and boiler conversion costs. Flue gas desulfurization analysis includes a procedure for estimating capital, operating, and maintenance costs for specific power plants predicated on the existence of a fully developed technology. System costs due to parasitic power consumption, increased forced outage, and decreased efficiency for flue gas desulfurization and low sulfur Western coal are also included. A number of factors are not included in the analysis conducted here. Specifically, it is assumed that the electric utility can sever a contract for coal without a penalty. Omitted from the analysis is a consideration of economic loss and social dislocation effects on the Midwestern coal industry, resulting from penetration of Western low sulfur coal. Low sulfur Eastern coal is not considered as a potential source of supply in this analysis nor is the possibility of other technologies, such as coal washing, considered.

Alternative emission limits for the states were investigated in the Midwest. Specifically, the present State Implementation Plan limitations, adoption of National Ambient Air Quality Standards limits, and supplementary controls were all evaluated. The important conclusion of this analysis is that both stack gas scrubbers and low sulfur coal are utilized in the Midwest;

however, generally one-third of the utilities chose scrubbers while Western coal was chosen by the remaining two-thirds. Scrubber utilization reached a maximum over a short time period of perhaps 3-5 years, after which it generally remained constant, reflecting the increased availability of low cost Western coal. This analysis is based on assuming that an electric utility would absorb a maximum cost penalty of 15% in choosing a control option in order not to request a variance. (That is, an electric utility is granted a variance if the least-cost control option is in short supply and the remaining control option is at least 15% more costly.) If strict enforcement of standards is applied and the utility must choose between coal and scrubbers, regardless of the cost, stack gas scrubber utilization is enhanced perhaps 60-100% and compliance can occur in a relatively short time frame of 4-6 years. However, a relatively stiff penalty results from this restriction as the annual costs borne by the electric utility industry increase 70-100% over the other options.

Delay of the various standards was also considered. Delay generally seems to favor the Western-based coal suppliers. As growth of this supply is already being stimulated, an increase in Western coal will be available at a later point, so that compliance could be obtained over a relatively short time frame once enforcement occurs. If time is allowed to develop such supplies, the end result could be that the scrubber industry would not develop due to the availability of low sulfur coal. Bearing this in mind, any delay policy must be sensitive to its effect on the development and utilization of scrubbers.

Moreover, the analysis indicated the sensitivity of the ultimate utilization of coal and scrubbers to the relative prices of these two control options. Specifically, a 15% relative change in the price of scrubbers and low sulfur coal could result in significantly increased utilization of scrubbers. Moreover, a 35% increase in the relative cost of low sulfur coal would reduce by over half its use in the Midwestern utility market. It should be noted that the capital charges account for 50-55% of annual compliance costs if a power plant uses scrubbers. On the other hand, the capital costs associated with low sulfur coal are rather small. Thus, selection of scrubbers is rather sensitive to the costs of the capital for electric utilities. Various subsidy policies such as changes in utility rate-recovery formulas could have a beneficial effect on scrubber utilization.

In general, the supply of scrubbers is more than adequate to meet the demand in the Midwest. Delaying the availability of Western coal to a later point in time with enforcement now will stimulate development of the scrubber industry, but such delays in Western coal availability ultimately slow the rate of compliance. However, early stimulation of increased availability of Western coal without at the same time stimulating utilization of scrubbers could result in increased availability of Western coal and little or no utilization of scrubbers.

Because of the impending clean fuel deficits and the unavailability of coal and control technologies, President Ford, in his State of the Union Address for 1975, proposed three activities to ameliorate the situation:

1. Voluntary revision of state emission limits.
2. Implementation of supplementary control systems.
3. Extensions of compliance deadlines to perhaps 1985.

Furthermore, significant research and development efforts are being expended to develop technologies, such as coal washing and gasification, that are applicable to solving these energy-environmental problems.

In light of these considerations and the results obtained in this study, a number of recommendations for further analysis are suggested.

1. The data base should be extended to 1990-1995 to permit analyses of delay of standards over a longer time frame, specifically to 1985. It should also be extended to a national perspective.

2. Policies for subsidizing the utilization of scrubbers, such as modifications in utility rate recovery formulas, should also be studied.

3. The analysis did not consider the availability of alternative coal supplies. Coal supply functions should be developed for Eastern sources of low sulfur coals, and a closer examination should be conducted of the cost and supply of coal from existing coal producing fields in the East and Midwest.

4. As coal washing and gasification appear as possible alternatives, it is recommended that the methodology be extended to include these technologies.

5. A demographic characterization of populations around power plants should be conducted to permit analyses of population exposure for alternative control policies.

6. The analyses should be extended to include the social and economic effect of alternative utilization patterns of flue gas desulfurization and low sulfur Western coal on the existing coal producing industry.

The attainment of standards that affect energy-related facilities has shown itself to be a process requiring the monitoring of the development of control technology, economic fluctuations, and air quality trends. If the regulatory structure of the federal program with respect to SO_2 and particulate control is to respond to changes in these areas, a method of monitoring these factors, specifically with respect to utility operations, is necessary. In assessing the results of this study of the interactive nature of such effects on the viability of the utility enforcement program, it should be remembered that changes in any of the technology price or control factors may have pervasive effects throughout the regulatory program. In order to assess the impact of such changes, we would recommend further efforts in contingency planning for alternative future scenarios such as the imposition of severe restrictions on the mining of Western coal, the lowering of coal and oil prices, and the further development of economically efficient control technologies.

1.0 INTRODUCTION

The imposition of limitations on the amount of sulfur dioxide that may be emitted from fuel combustion sources has raised a number of serious questions regarding the potential economic dislocation in industries affected by these plans. One of the most important potential market readjustments regards the changes in fuel use patterns and the demand for air pollution control equipment by electric utilities in the Midwest. In this region, utilities are highly dependent on high sulfur Midwestern coal as a fuel source. State Implementation Plans require either a reduction from 4% to less than 1% in the sulfur content of coal employed by utilities or the installation of some type of abatement equipment. In terms of available control strategies, this means that Midwestern electric utilities must be committed to either the purchase of low sulfur fuel (mainly from Western states) or to the installation of sulfur dioxide scrubbing devices by 1975.

Several studies[1-3] have indicated that a strict adherence to the present schedules and prescriptions of the State Implementation Plans in the Midwest may cause low sulfur fuel shortages and place demands that it cannot meet on the sulfur dioxide scrubbing industry. This situation has created the need to reexamine the timing and severity of the State Implementation Plans with regard to the electric power utilities and to ascertain the air quality and economic implications of changes in these state regulations.

This study attempts to make such an investigation, specifically with regard to the electric utilities in Illinois, Indiana, Michigan, Ohio, and Wisconsin. The effect of changes in fuel use and control device installations over the 1975 to 1982 period under various scenarios that describe possible changes in the State Implementation Plans are examined. The analysis required investigation and model development in six subject areas:

1. Federal Power Commission data on power plant characteristics and utility building programs were utilized to project the generating requirements of utilities in these states.

2. Price and availability projections of low sulfur Western coal were developed over the period in question.

3. The state of the art of sulfur control technology, its availability, and associated cost were investigated.

4. The relationship of air quality to fuel use, power plant characteristics, and control technology in power plants was analyzed.

5. A study of the effects of the requirements to use low sulfur fuel or sulfur dioxide control technology on the cost of utility operations was carried out.

6. A policy analysis model was developed that is capable of evaluating on a plant-by-plant basis the electric power utility's choice between the use of low sulfur fuel or scrubbers; given the availability and price of fuel and control technology, the effects of fuel decisions on utility system costs, and an assumed control policy (see Fig. 1.1 and App. I).

For those readers less interested in the methodological description, an analysis of the policy results of the study effort can be found in Sec. 6.

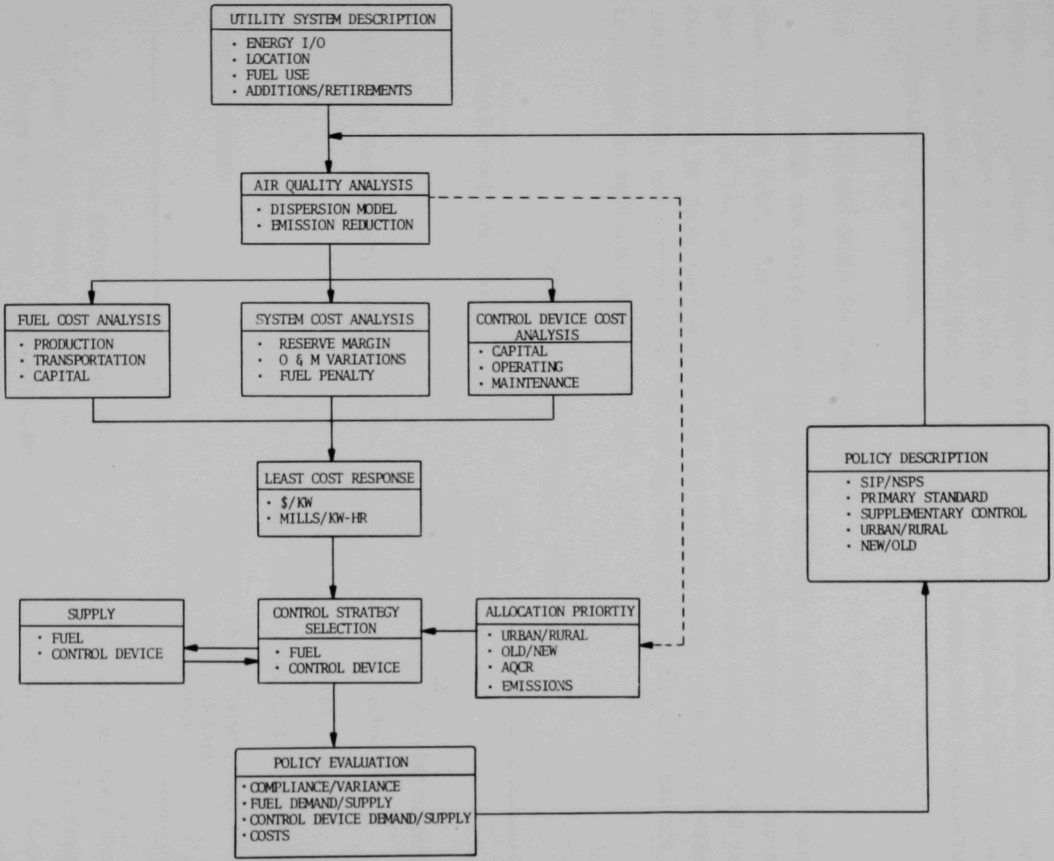

Fig. 1.1. Air Quality Policy Analysis of Electric Utilities

2.0 STUDY APPROACH

The method of policy analysis used in this study is a simulation of least-cost response by electric utilities. The analysis responds to the sequence of standards contained within each policy, estimates the cost for individual power plants of each possible method of compliance, and then proceeds forward in time to allocate supplies against demand until equilibrium and compliance are achieved.

2.1 COSTS AND OTHER FACTORS CONSIDERED

Within the policy analysis, a cost analysis is performed for each plant in each year. The capital and operating costs of both control devices and the use of low sulfur coal are estimated. All costs are calculated in 1974 dollars in three cost models; low sulfur coal (LSC), flue gas desulfurization (FGD), and system costs. It is important to note the cost factors considered in each cost model (see Table 2.1).

Table 2.1. Cost Factors Considered

Low Sulfur Western Coal:	Production Transportation Boiler Conversion High Sulfur Coal Cost Extrapolated
Flue Gas Desulfurization:	Fully Developed Technology Capital Operating (material, labor) Maintenance High Sulfur Coal Cost Extrapolated
System Costs:	Parasitic Power Consumption Increased Forced Outage Decreased Efficiency

The low sulfur coal cost analysis considers production costs for three sources of Western LSC (see Sec. 3). They are, in order of increasing cost, large strip mines, less efficient strip mines, and underground mines. The cheapest coal for which supply is still available in each year is chosen. Transportation costs are estimated using distance (miles) from the coal fields to the power plant. A variable rate formula is used to account for freight rate sensitivity to the annual volume of shipments (see Sec. 3).

Each power plant purchases only enough low sulfur coal to meet the required emission limit. The Western coal is mixed (for use in the same or different boilers) with coal of the sulfur content used by the power plant in the base year, 1971. A charge is assessed for boiler conversion to enable Western coal to be burned. The conversion is proportional to the amount of Western coal used. The coal conversion is estimated to cost $10/kw for dry-bottom design boilers and $35/kw for wet-bottom boilers that require extensive rebuilding. These capital charges are annualized over 15 years at 17% per annum -- the same basis of capitalization used in scrubber cost analysis.

A critical assumption of the fuel cost model is that any existing fuel contract for a power plant can be ended or reduced without penalty. If the policy scenario being simulated imposes such stringent emission limits that the acceptable fuel mix is almost entirely Western coal, then this assumption is almost certainly not true. The cost of reducing an existing coal contract will, of course, vary for each plant dependent upon the length, size, and number of existing contracts. The availability of low sulfur Eastern coal is not considered in this analysis.

Omitted from the cost calculation is any consideration of economic loss and social dislocation effects on the Midwestern high sulfur coal industry. While such costs are no doubt quite important, it can be reasonably assumed that they will influence utility response to sulfur regulations only insofar as they are borne by the utility. A measure of the costs a utility would have to pay for such regional economic loss is the penalty for breaking an existing long-term contract. The extent of these regional losses and their impact on utility cost calculations should be analyzed in the future as functions of various policy scenarios.

Control device capital and operating costs are estimated using the methods described in Sec. 4. All costs are extrapolated from the 1972 dollar estimates to the 1974 dollars used in the analysis. It should be emphasized that all the costs, both capital and operating, are for fully developed technologies. Thus, there is the implicit assumption that developmental and pilot plant work has all been accomplished before the policy scenario imposes an emission standard. In the absence of any strong incentives, it is open to question, whether the technology will be even close to this point by 1977, the target year of most of the policies analyzed. It would also be erroneous to assume cost reductions due to technology development even by the end of the decade, since, barring any spectacular breakthrough, the costs estimated in this study presuppose that this developmental process has been accomplished.

Although the model has the flexibility to calculate costs for several types of sulfur dioxide scrubbers, only the lime/limestone scrubbing method is used due to lack of data on other types. This does not introduce serious error into capital costs, but may for some plants be inaccurate for the operating cost components. An average waste disposal cost of $3.00 per ton is used for all plants. Most probably, urban area power plants would choose only a scrubbing process that yielded a salable product in order to avoid sludge disposal problems. The effect of such a choice, if any, was not estimated due to lack of data.

The model requires each power plant to scrub only that portion of its effluent necessary for compliance with the emission standards contained within the policy scenario. The capital costs are calculated on a $/kw basis as if the entire effluent stream were being passed through the scrubber. The actual capital cost is then linearly reduced to that fraction of plant capacity that requires a scrubber in order to comply with the specified emission limit. This assumption of linearly proportional reduced costs is critical, but appears justified because only very slight economies of scale are believed to exist for scrubbers.

Capital costs are distributed over a 15-year period at an annual cost of 17%. If the data set contains information on a plant retirement in less than 15 years, the annual charge rate is appropriately changed. Since about half the total annual cost of FGD is the cost of capital investment, the competitive viability of this option is critically dependent on the several components of these capital charges -- interest, taxes, and tax credits.

Operating costs for FGD are based on the cost and sulfur content of the coal used by each plant in the base year, 1971. Parasitic power and steam consumption are included in the operating costs, but effects of scrubber reliability are treated by the system cost analysis. It is important to keep in mind when studying the policy analyses that all FGD costs are tentative estimates based on limited, pilot installation data. The sensitivity of FGD utilization to cost changes of 10% to 25% in these analyses is marked (see Sec. 6).

In addition to the direct costs of compliance, there are further system operation costs incurred by the utility. System costs arise from the need to maintain reliability while complying with the imposed emission standards. Reliability is decreased by emission controls both because of increased unit forced outage and because of loss of generating capacity. The increase in forced outage rate primarily affects FGD costs, but very slight increases are associated with LSC due to the additional ash. Loss of generating capacity for a unit is due to parasitic energy consumption when running a scrubber or a larger precipitator. Also, the need to handle large quantities of lower quality Western coal causes a drop in plant efficiency.

These system ramifications of emission control were investigated by means of parametric studies of a synthetic but representative utility system (see Sec. 5). For each power plant in the region, the annual load factor is used to approximate the unit position in a system loading order. The costs, expressed as mills/kw-hr, are assumed to apply to the individual power plants examined in the policy analysis. The approximate additional system costs are then added to the annual compliance costs for both the LSC and the FGD options. Implicit in this transfer of costs from the synthetic system to real power plants is the assumption that all utility systems in the region enjoy equal reliability and have much the same patterns of demand for energy and of scheduled maintenance. This is a reasonable assumption, and any more sensitive analysis would require massive amounts of proprietary data.

It can be hoped that over the next decade FGD reliability will improve significantly or be made independent of plant reliability. Such improvements would improve the economic viability of scrubbers, but the loss of available generating capacity to operate the scrubber would still cause a reliability cost penalty. A Sensitivity Analysis of these cost factors is presented in Sec. 6.

2.2 DESCRIPTION OF THE METHODOLOGY

The policy analyses are accomplished by a simulation of least-cost responses as shown in Fig. 1.1. An inventory is made of power plants in the region and their fuel and emission characteristics, and the regional data base is projected ahead for ten years. A policy scenario is translated into a timed sequence of air quality regulations that are imposed on the power plants in the region. Cost estimates are made of various possible methods of compliance, and the lowest of these is chosen subject to supply limitations. The results of this plant-by-plant and year-by-year simulation are aggregated to give a regional picture of compliance, variances, and demands for clean fuel and control devices.

The data base contains descriptions of each power plant in the base year, 1971, and projected additions and retirements. Wherever detailed information is available, plant data is recorded by individual generating units, or groups of similar units. The data include energy input and output, fuel mix, and fuel costs for the base year. Location variables for each plant include the state, AQCR, county, urban or rural setting based on SMSA, distance to Western coal fields, and nearness to Midwestern coal production areas.

Where data are missing, reasonable approximations based on similar plants and on regional and state average characteristics are used. If disaggregate data on generating units within a plant are available, they are used to build up representative characteristics for the plant. Such data include age, fuel capability, boiler design, and annual average utilization.

Information on existing power plants was gathered from three basic sources:

1. Federal Power Commission Forms 67 for 1971.
2. NCA: 1972 Edition of Steam-Electric Plant Factors.[4]
3. NERC: Reports by ECAR, MAIN, and MARCA.[5,6,7]

The utilities' projections of new power plants and changes to existing ones were used. All three of the above sources contain projections drawn from the utilities. Discrepancies over the several sources were resolved using the most recent information. Although it can be said that the utilities' projections of capacity expansion may well be an overstatement, slippages on nuclear unit construction schedules may cause the fossil-fuel capacity projections to be reasonably accurate if not understated. No attempt was made in this study to make an independent estimate of energy demand and resulting necessary capacity changes.

For each new plant, the proposed location and fuel use are included, if known. If the fuel use was not known, coal is assumed to be the intended fuel. Existing plants are assumed to continue with the 1971 fuel mix unchanged through the study period of 1982. The future of many plans for coal to oil conversion is uncertain, but it is reasonable to assume that any conversion not complete by the end of 1972 is either delayed or canceled.

A ranking of power plants can be accomplished, if desired, to arrange the power plants in an order of increasing need for compliance and thus selection of scarce resources (FGD or LSC). It is also possible to require or preclude certain responses for certain classes of plants. This flexibility permits both an air quality implementation policy and a selective variance policy to be analyzed. Power plants may be grouped according to one or more of several descriptions such as size, age, and location. Each group of power plants is assigned a priority (i.e., priority allocation). The highest priority category is the first to receive scarce supplies. Or, to look at it the other way, the highest priority category is the last to receive a variance. In the absence of any external specification, the annual SO_2 emission reduction required is the criteria for prioritization. If priority categories are specified, then annual emissions rank the power plants within the groups. For the analyses reported here, new power plants were given highest priority for allocation -- or lowest priority for any variance.

The policy scenario to be investigated is translated into an array of emission limits covering various categories of power plants and coming into effect in various years. It is this sequence of emission limits that drives the response simulation.

Emission limits may be specified as such, or as an ambient air quality level. In the latter case, a worst-case dispersion model is used to calculate for each power plant the upper bound on permitted emissions. In either case, the allowable emission rate is compared against the actual emissions of a power plant in order to find the reduction required for compliance. This reduction must be accomplished by low sulfur fuel or a control device. As mentioned above, this same reduction in emission is an input to the allocation priority scheme.

A cost analysis is then performed for each plant analyzing both low sulfur coal and control devices. All costs are calculated in 1974 dollars. It is important to note that each plant is required to reduce emissions only to the legal limit. This is not an all-or-nothing response; rather, low sulfur fuel and flue gas desulfurization are utilized only to the extent necessary to accomplish the emission reduction.

The least-cost compliance comparison is made for each plant each year. The comparison is between the total annual cost of the two options, LSC and FGD. The least-cost response is sought subject to supply limitations. If, in any annual period, a plant installs a control device, that control device must be retained until the end of the simulation period regardless of cost. The use of LSC, however, is subject to cost comparison and supply availability in each year, since the capital carrying charge for this response is minimal. Thus the use by a particular plant of LSC in any given year does not predetermine the use of LSC in any subsequent years.

Supply functions are input to the simulation both for control devices and for Western coals. The supply function for FGD was derived from the SOCTAP report[8] with national availability prorated to the study region on the basis of fossil-fuel generating capacity. The supply in each year is sensitive to the preceding rate of increase in FGD demand. The availability of FGD is projected to increase very rapidly if, and only if, there is continuing demand by the utility industry. The supply functions for Western coals grow essentially at the maximum rate made possible by capital and equipment. The annual growth rate of about 25% is considered to be the maximum that can be sustained by any industry without inordinate cost increases. The coal supplies are also sensitive to demand, so that if demand were ever to slacken, subsequent rates of expansion would be reduced.

In the face of insufficient supply, the available coal and scrubbers must be allocated using the priority rating described above. This priority system gives the order for allocation of available supplies (i.e., the inverse order for priority in granting variances). In each year, supplies are allocated down the priority list until they are exhausted. Each plant follows the least-cost response if supplies permit. If the supply of the least-cost response is exhausted and if the cost difference does not exceed 15%, the next higher cost response is chosen. This 15% cost difference approximates the cost overrun a utility would accept in order to avoid litigation and penalties arising from noncompliance.

When supplies are exhausted in any given year, plants lower on the allocation priority list are given a variance until the following year. Any power plant that cannot comply because the required emission reduction is too severe is so indicated and given a variance. If a particular power plant can possibly comply by only one option, that option is not assigned without regard to cost. Instead, the 15% cost difference is used to dictate whether the plant complies or is given a variance. No plant is required to use both low sulfur coal and a scrubber in order to comply with emission standards. Regardless of supply availability, costs for each compliance option are calculated in order to determine the excess or unsatisfied demand at least cost.

This sequence of emission standard, cost estimation, and least-cost response, when done for each plant in turn, gives a regionwide year-by-year pattern of demands, costs, and compliance. The pattern of compliance over the ten-year study period can be interpreted to assess the air quality improvements resulting from policy scenarios as well as the variances required by limited supplies of low sulfur fuel and control devices. The patterns of utilization and unsatisfied demand at least cost give a picture of the future of both the scrubber industry and of Western coal production under various policy assumptions. The costs incurred by utilities year by year in order to comply with various air quality regulations permit a cost-effectiveness analysis of potential policies.

3.0 LOW SULFUR WESTERN COAL IN THE MIDWEST

The prices of low sulfur Western coals selling in the Midwestern electric utility market have been estimated for the period 1974 to 1982. The price estimates follow from a cost analysis of Western coal production and transportation that takes into account possible constraints on the rate of Western coal development.

Lowest prices for "new" Western coal will occur under conditions of demand growth of less than 25% per year. This lowest-cost coal will consist mostly of low-rank (8300-8800 Btu/lb) subbituminous coal produced from large surface mines in the Powder River Basin in Wyoming and Montana. Output of higher quality subbituminous coal will also expand; however, constraints on reserves availability will cause the market share of this coal to decline. For Western coal demand growth in excess of 25% per year, shortages of large-scale surface mine equipment will force the opening of smaller surface mines in the Powder River Basin and will encourage the development of underground bituminous mines in other Western coal regions.

Shipment by railroad will remain the principal transportation mode to the Midwest, with rail/water routes favored for many plants located on the Great Lakes and the Inland Waterway System. The analysis of current railroad rates shows that they are reasonably well approximated by the relation $r = 6.3 + 600/X$, where r is the unit cost of transportation (mills per ton-mile) and X is the size of the annual shipment (thousands of tons per year). Transportation costs, expressed in constant dollars, are projected to increase by 3% per year.

A simplified presentation of delivered coal price estimates for 1974 and 1982 is given in Figs. 3.1-3.4. In the policy analysis model, LSC costs are computed for each power plant as described in Sec. 2. The figures, which correspond to two different demand growth scenarios, show prices as a function of market distance for coal produced and delivered under high-volume, long-term contract. The price frontiers shown in Figs. 3.1 and 3.3 refer to deliveries of bituminous and subbituminous coals produced under conditions of low demand growth. Demand growth in excess of 25% per year will allow the marketing of subbituminous coal produced from less efficient surface mines. Estimated costs under the high demand growth scenario are shown in Figs. 3.2 and 3.4. The nominal price advantage of subbituminous coal ($\sim 10¢/10^6$ Btu at the Ohio-Indiana border in 1974) is largely offset by the superior combustion properties (particularly the higher ash-fusion temperatures) of the bituminous coal.

Under both the high- and the low-demand growth scenarios, higher rank subbituminous coals are likely to remain scarce. This means that producers of the higher rank coals will be able to raise their mine prices to levels that will equate the delivery prices (cents per million Btu basis) of the high- and low-rank coals. Table 3.1 lists estimated 1982 mine prices of subbituminous coals of different heating values for an assumed shipping distance of 1200 miles.

The Low Sulfur Coal (LSC) supply functions were derived from Coal Age projections as reported by Asbury and Costello.[9] There are three types of LSC considered, and each has a unique supply function.

Type 1 represents large strip mines in the Powder River Basin. This is 8300 Btu, 0.5% S coal produced at $2.31/ton in 1974. The initial supply is 9.75 M tons in 1974 with growth at 25% per year. This is considered to be the maximum rate of expansion for this type of production.

Table 3.1. 1982 Mine Prices for Subbituminous Coals of Different Heating Values (Shipping Distance = 1200 miles)

Coal Heating Value (Btu/lb)	Mine Price: Demand Growth < 25%/yr $/ton	(¢/MBtu)	Mine Price: Demand Growth > 25%/yr $/ton	(¢/MBtu)
8,300	3.66	(22.0)	5.49	(33.1)
9,000	4.84	(26.9)	6.84	(38.0)
9,500	5.70	(30.0)	7.81	(41.1)
10,500	7.39	(35.2)	9.72	(46.3)

Type 2 represents smaller, less efficient strip mines in the same region producing at $3.47/ton in 1974. The supply from these mines was estimated to be: 0.5 M tons in 1974, 6.0 M tons in 1978, 10.0 M tons in 1980, and 14.0 M tons in 1982.

Type 3 represents underground mining in Utah and Western Colorado. This is 12,200 Btu, 0.6% S coal that could be produced at $8.59/ton in 1974. No coal from these mines was predicted to be available until 1977 when 6.0 M tons could be produced. Thereafter, output could grow at 50% per year.

The growth rates indicated above are maximum rates of increase. In each year, the supply of coal grows at a lesser rate if in the previous year not all the available supply was used up.

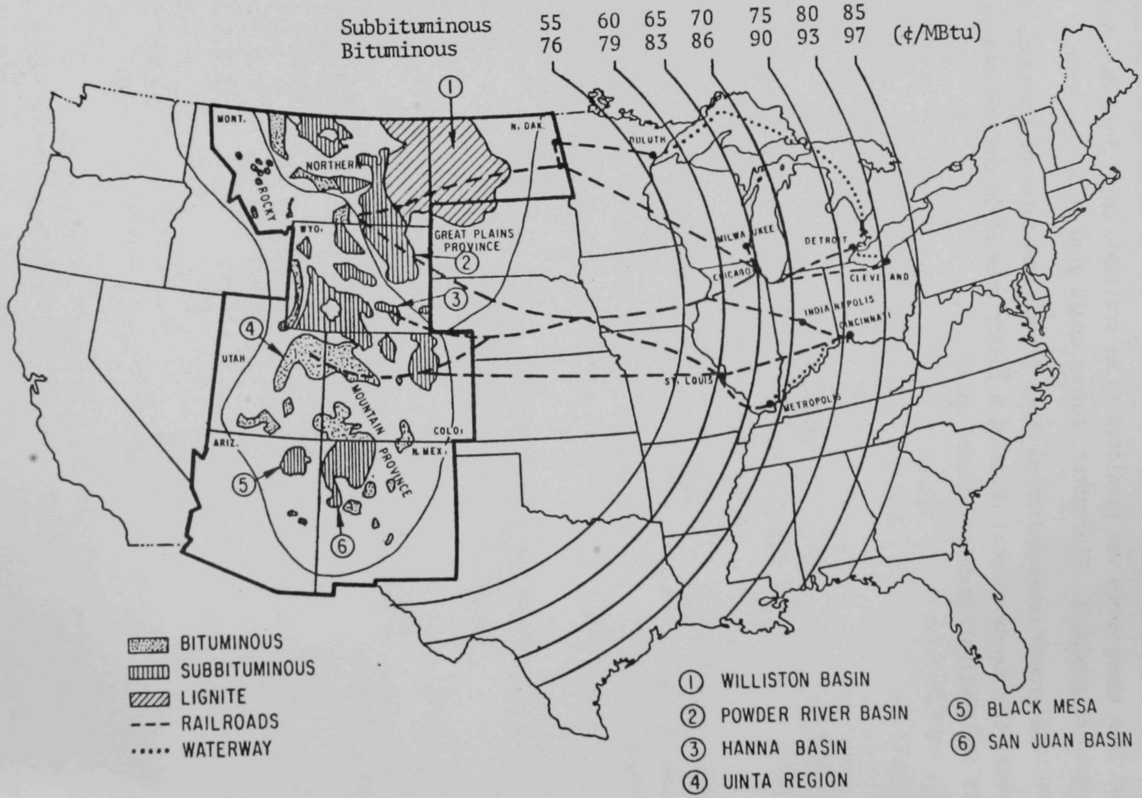

Fig. 3.1. 1974 Prices of Western Coal in the Midwest Market, Demand Growth < 25%/Year
ANL. Neg. No. 190-1507.

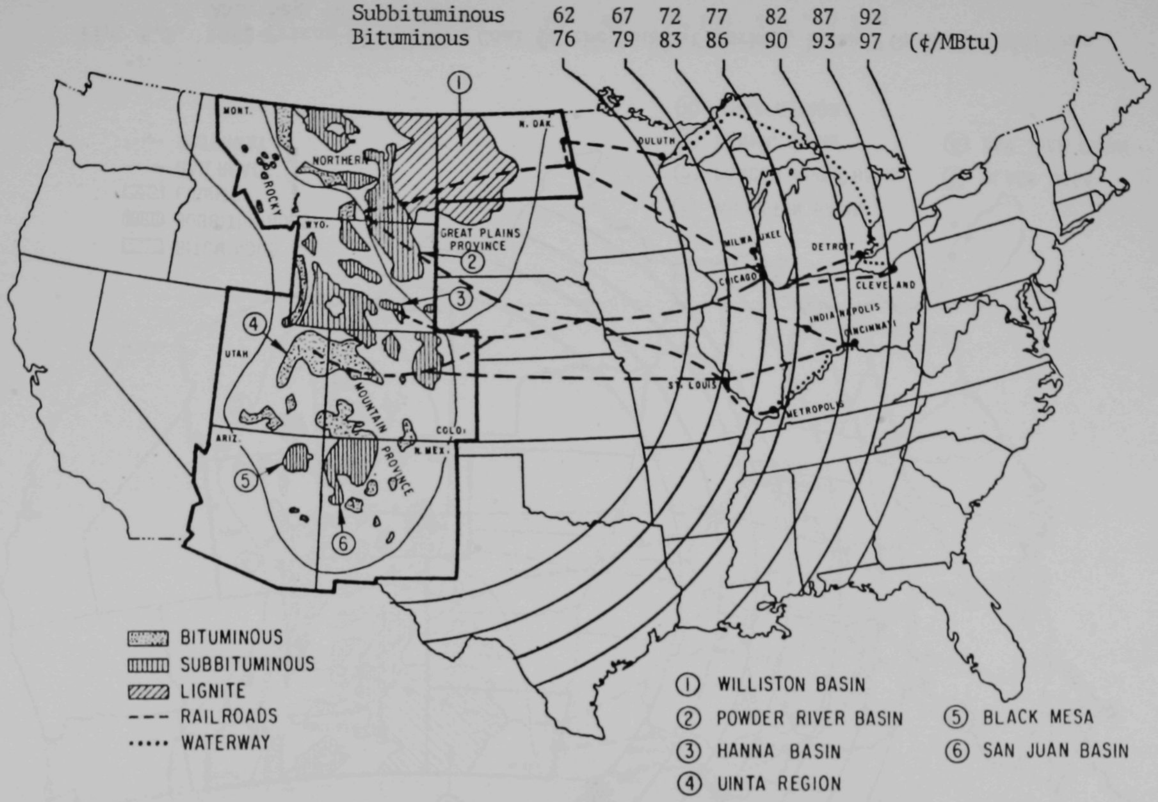

Fig. 3.2. 1974 Prices of Western Coal in the Midwest Market, Demand Growth > 25%/Year
ANL. Neg. No. 190-1508.

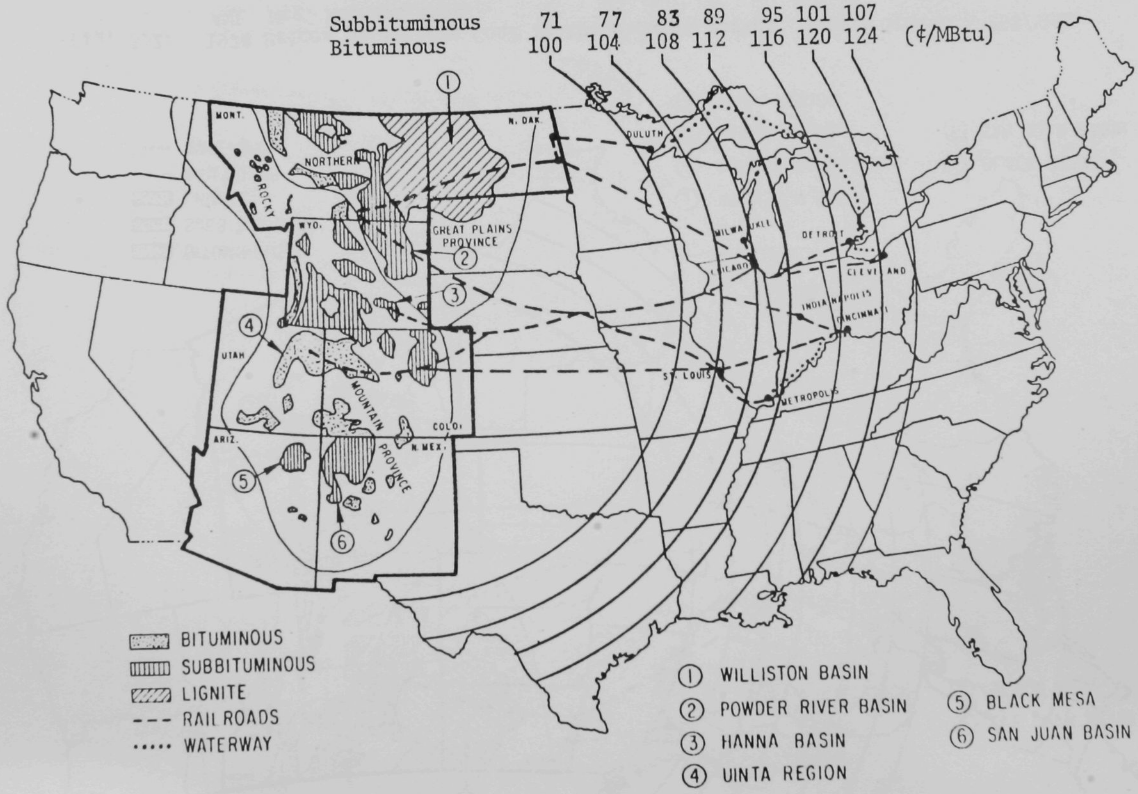

Fig. 3.3. 1982 Prices of Western Coal in the Midwest Market, Demand Growth < 25%/Year
ANL. Neg. No. 190-1509.

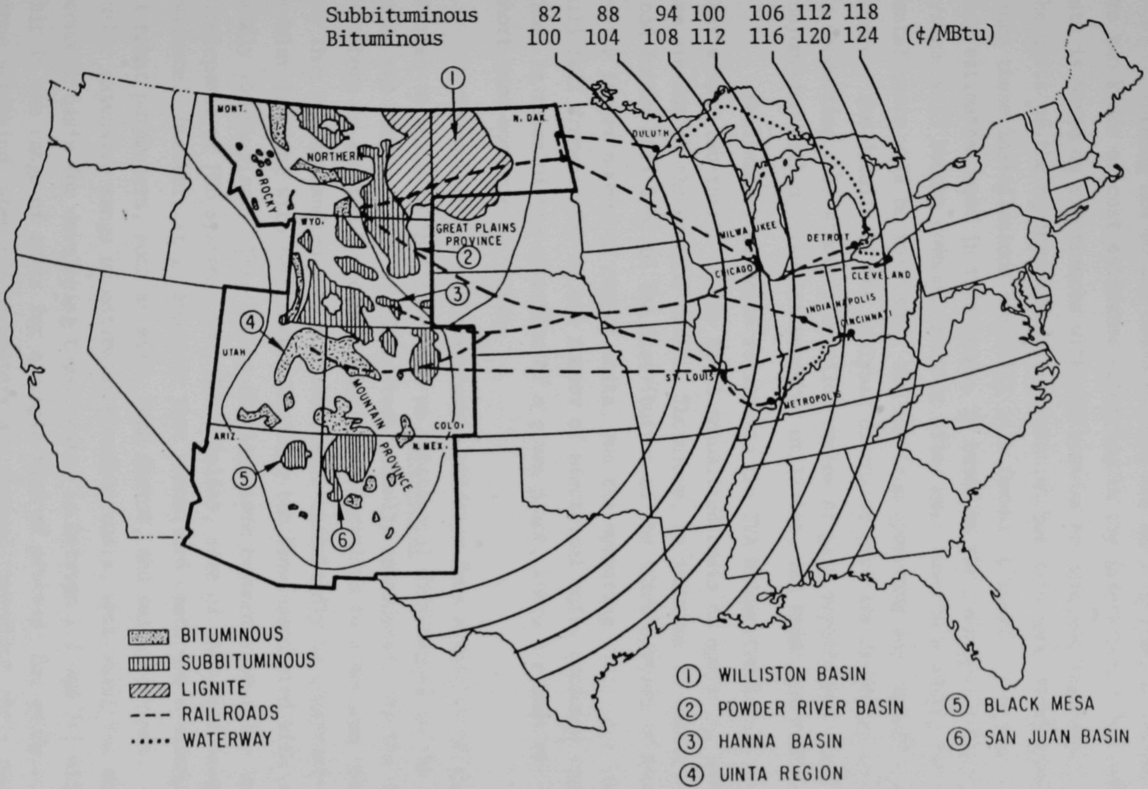

Fig. 3.4. 1982 Prices of Western Coal in the Midwest Market, Demand Growth > 25%/Year
ANL. Neg. No. 190-1510.

4.0 SULFUR DIOXIDE CONTROL TECHNOLOGIES

Turning now to the costs of Flue Gas Desulfurization systems, there are two kinds of cost estimates appearing in the literature. One cost estimate is based on experiences with FGD systems to date and represents not only the costs of the equipment and its operation but also some developmental costs, since these installations are still in a formative stage. A second set of cost estimates, used in this study, is based on the presumption that FGD systems will become common, and that after many have been built, the developmental costs will be very small and the true operating and capital costs will remain. The details of the analysis discussed here are presented by Hurter.[10] In conducting this study, a detailed review of past reports was carried out in conjunction with a survey of vendors, utilities, and trade associations.

Preliminary evidence related to the TVA Widows Creek unit indicates that almost two-thirds of the total annualized costs of operating an FGD system are due to the capital costs. Therefore, an increase in annual plant load factor will lead to the distribution of the fixed portion of annual costs over a larger number of output units, and the operating costs on a kw-hr basis will fall dramatically as the number of electrical units produced increases. Thus, in terms of the operation of a given plant, there are what may be called short-term economies of scale.

There seems to be considerable evidence from a variety of different sources to indicate that there are no substantial differences in the cost of using the various kinds of FGD systems normally considered. As the design of scrubbers is limited by technological considerations to a maximum volume of gas that can be handled, the scrubbers will undoubtedly be constructed in a modular fashion, with each module handling the flow associated with an approximately 150-Mw plant. This limits the long-term economies of scale in the development of FGD systems, but, nevertheless, some of these economies are in evidence. However, it is apparent that annualized costs are a strong function of plant parameters, such as size, load factor, and sulfur content. The rather extensive range of estimated possible costs, when using the engineering-economic basis for developing these costs, is between 1.1 and 7.7 mills/kw-hr. This is the range of costs for a single kind of process; for example, limestone scrubbing, when the parameters are changed throughout their range.

This range is particularly important since it far exceeds the range of differences between types of processes when all of the parameters are considered at their normal or most likely levels.

The cost estimating model used in this study for FGD systems includes (1) utility and raw material consumption, (2) operating labor costs, (3) maintenance costs, and (4) capital charges. The costs are a function of plant size, load factor, sulfur removal rate, and retrofit difficulty. The model used in this policy analysis, which is based on work by Burchard,[11] for estimating the costs of FGD for individual power plants is described in App. III. This engineering-economic analysis of scrubber alternatives indicates a cost range of 2.2-2.5 mills/kw-hr, or a capital cost range of $34.60-$46.00/kw. These are the costs from a variety of different processes, including limestone scrubbing, lime scrubbing, magnesium oxide scrubbing with regeneration, alkali scrubbing with thermal regeneration, and alkali scrubbing with electrolytic regeneration. In each case, the most likely values of the parameters are used in computing the costs.

Annualized costs for waste disposal, a difficult problem, ranged from $1.00-$7.00/ton, and $3.00/ton is used. A value of $15.00/ton for sulfur, or for the sulfur content of sulfuric acid as resale, is used.

It should be noted that the 1972 average national consumer costs for power were about 17.8 mills/kw-hr; while, as we have already seen, the 1972 average costs of FGD is about 2 mills/kw-hr. On the basis of these figures, consumer costs for electricity could rise by 10% through the wide scale adoption of FGD systems. Of course, the increase in cost will be much larger for consumers who happen to live within areas where power is generated almost exclusively through the burning of coal.

When turning to the diversity of cost estimates that appear in the literature, it must be kept in mind that actual operating experience with FGD systems is very limited indeed. Consequently, the numbers presented are estimates, and nothing more. Capital costs on a per kilowatt basis presented in the literature range from $30-$100. Some of these cost estimates are for new plant, and others are for retrofit. Some include the cost of sludge disposal, and others do not.

A key factor in determining the rate at which systems could be installed is the length of time an installation takes. A vendor may state that four systems could be installed at a time, but if each system takes four years to install, then he is able on the average to install only one a year. Experience to date indicates that a system installation takes 27-36 months.

Although present installation of FGD systems seems to be limited by the demand by users for the systems, the vendor capacity is expected to grow at a rapid rate; so that in the relatively short time up to, say, 1979, vendor capacity will equal or exceed the needed capacity. Since demand is presently the limiting factor as far as installation of systems is concerned, it is unlikely that all the potential under-capacity will be used up in the years immediately following. A major determinant of this market will be the vigor with which the state and federal environmental protection agencies push the sulfur oxide compliance requirements, especially in the form of emission limitations. After all the time and energy expended on the installation and development of FGD systems, fewer than ten systems are actually in operation at the present time. Furthermore, many installations of various types have been tried and discarded.

Nevertheless, the final report of the Sulfur Oxide Control Technology Assessment Panel (SOCTAP)[8] states that technology does not appear to be a limiting factor in utilization of stack gas cleaning. "The SOCTAP task force believes that the required high reliability of FGD systems will be achieved with the early resolution of a number of engineering problems for which specified solutions have already been developed and demonstrated at one or another location."

One form of evidence on this question would be the reliability data from operating scrubber units. Reliability data were sought from seven plants that, in one way or another, were considered to be in operation. None of the plants had enough operating experience, during which time the scrubbers actually operated, to provide figures, except for the Commonwealth Edison Will County plant. The Will County plant uses two scrubbers designed to operate in parallel and to take the entire flue gas output. In 1972, one scrubber was available 32% of the time; the second, 26% of the time; and the two together, 8% of the time. The availability figures fell to 27% for the first scrubber, 5% for the second, and less than 1% for the two combined during 1973. At the last available notice, both scrubbers are now shut down.

An interview study of "experts" made by Battelle[12] in the spring of 1973 indicates that there is little difference among the various individual processes in terms of expected reliabilities. A 90% onstream or availability factor for the closed-cycle, stack gas treatment process on a 100-Mw-or-greater, coal-fired utility plant in the United States will not be available until 1976 at the earliest. One-third of the respondents in the Battelle survey felt that none of the major processes would achieve 90% availability until after 1980. In the analysis conducted here, a 90% availability was used (see Sec. 5).

The control device supply function was derived from estimates of vendor capability made by the SOCTAP study.[8] National supply was prorated to the study region on the basis of fossil-fueled capacity.

The supply function is demand responsive, the initial supply is 880 Mw in 1975. The cumulative supply in each year is

$$\text{Supply}_{(t)} = \text{Supply}_{(t-1)} + \text{gf}(\text{Installations}_{(t-1)} - \text{Installations}_{(t-2)}).$$

The growth factor (gf) is 215% up to a supply of 21,000 Mw; thereafter, the growth rate is 115%.

5.0 GENERATING SYSTEM CONSIDERATIONS

The purpose of this section is to record the results and bases for calculating generating system operational costs that result from two alternative strategies: burning low sulfur fuel and using flue gas desulfurization (FGD) systems.

The economic aspects of policy analysis encompasses many cost factors; the work described herein pertains mainly to generating system effects on a one-year basis. In particular, the following effects are included:

Changes in system reliability due to increase in forced outages of plants with added equipment.

Changes in the distribution of energy generation among the units in a system caused by the use of LSC and FGD.

Changes in efficiency of electrical generation for plants using low sulfur fuel and flue gas treatment facilities.

Changes in plant capability due to a higher in-house use of power.

Changes in operation and maintenance costs caused by the auxiliary or increased processing of fuel and waste streams.

It is readily seen that many factors are omitted, most noticeable are the changes in plant capital costs due to the addition of the facilities, but these capital costs are included in the larger analysis program (see Sec. 4).

The approach used is to calculate the system's operational costs that include a reference generating unit burning its normal fuel; costs are then calculated for the system that contains this same unit burning low sulfur fuel, and, finally, with the unit burning high sulfur fuel with flue gas desulfurization facilities. For each of these three situations, costs are assigned to the unit being studied and annual differential costs are estimated. A large number of cases are investigated to show the influence of fuel costs, incremental forced outage rates, and unit size.

The SYSREL code[13] is the main calculational tool used in this study; however, some hand calculations are used for estimates of simple cost factors.

The code, SYSREL, deals with maintenance scheduling of generating units, needed generating reserve margin for a specified reliability criterion, allocation of electrical energy to the individual generating units of the system, and generating costs. The reliability calculations are based on the loss-of-capacity method. The energy allocation portion of the code determines energy generated by each unit based on the system load, forced outage rates of the units, and loading order of the units (or portions of units).

An electrical generating system was modeled, for the region being studied, that was reasonably representative of a utility system but without being completely like any actual system. Appendix IV describes the system considered and the results in detail.

Figure 5.1 summarizes the results obtained. The penalty in mills/kw-hr is independent of the size of the unit, being principally affected by the annual capacity factor. These results are added to the cost estimates described in Secs. 3 and 4 to obtain the total costs for low sulfur coal and FGD systems.

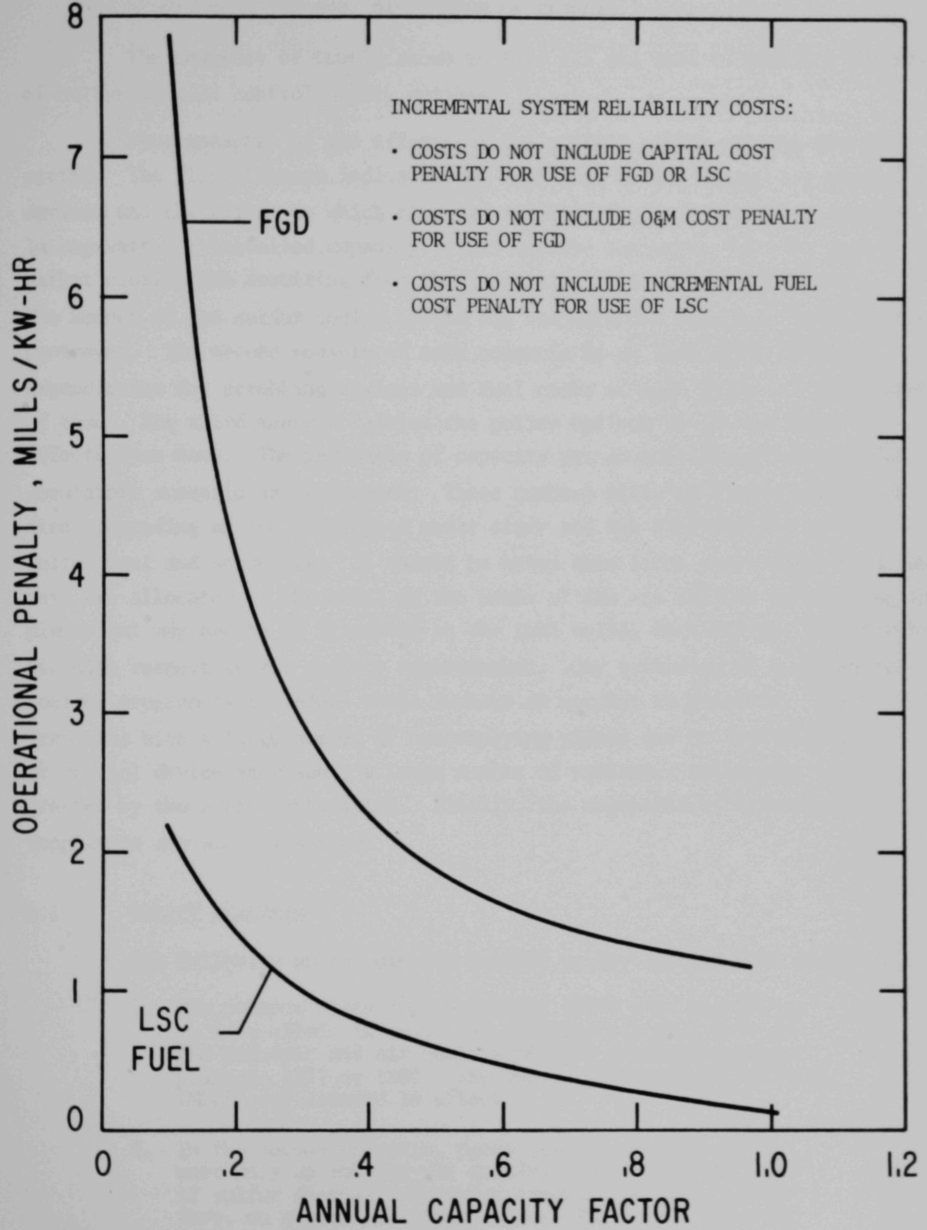

Fig. 5.1. Generalized Reliability Costs

6.0 DISCUSSION OF RESULTS

The sequence of models shown in Fig. 1.1 was used to assess a variety of sulfur dioxide control policy options.

Four measures of the effects of the control policy options are presented. The first measure indicates the magnitude of the demand for control devices and the extent to which they are supplied for each year, as expressed in megawatts of installed capacity. This measure indicates the time path to market equilibrium resulting from the imposition of a policy alternative. The amount of low sulfur coal supplied and demanded for each year is similarly portrayed. The second measure of each scenario is an indication of annual expenditures for scrubbing devices and fuel costs of each policy as a function of time. The third measure relates the policy options to the air quality effects over time. The megawatts of capacity not in compliance with a given regulatory scenario are presented. These numbers will, of course, vary over time, depending on the regulation under study and the availability of low sulfur fuel and scrubbers. It should be noted that since scarce fuel or scrubbers are allocated in the model on the basis of the air quality surrounding the plants but may not be so allocated in the real world, this measure is optimistic with respect to air quality improvements. One criterion of a successful control program is to reduce these numbers as quickly as possible. For scenarios with a large number of noncomplying plants due to fuel deficits or control device shortages, a large number of variances would have to be granted by the state authorities. Finally, the megawatts of capacity in compliance are also presented.

6.1 POLICY ANALYSIS

The following sulfur dioxide control policy options were analyzed:

1. The present State Implementation Plans were assumed to go into effect in 1975. An analysis was also made of the economic and air quality effects of delaying these plans to 1977 or 1980. New Source Performance Standards (NSPS) are assumed in effect.

2. In the second scenario, power plants are required to meet only an ambient air quality standard of 290 $\mu g/m^3$ of sulfur dioxide. Emission limitations vary, therefore, on a plant-by-plant basis. The impact of alternative compliance dates for air quality standards of 1975, 1977, and 1980 were analyzed.

3. The third scenario assumed that rural plants could use intermittent control techniques until 1980 and therefore have no constant emission limitations. Urban plants were required to conform to present State Implementation Plans.

4. The final scenario was developed to investigate how sensitive potential fuel deficits were to the delay of the New Source Performance Standards. The ambient air quality standards were analyzed as in scenario 2, but when the compliance schedule was delayed, the New Source Performance Standards were also delayed.

The policy analysis gives insight into the relationships between various federal and state policies and resulting patterns of compliance. The ways in which a range of policy changes can affect changes in rates and modes of compliance were investigated. Figures 6.1 through 6.9 show the results of the analysis graphically; the numerical results are given in App. V.

In examining the first two figures, a comparison of the effects of imposing State Implementation Plan (SIP) regulations as opposed to requirements to meet National Ambient Air Quality Standards (NAAQS) can be seen. Noncompliance, expressed in megawatts of capacity not in compliance, is significantly larger and more persistent for the SIP regulations. If the policies were to be implemented in 1975, compliance would be essentially complete by 1982 for the NAAQS; but noncompliance with the SIP regulations would be 15,000 Mw or 15% of the regional capacity. These noncompliance figures may be interpreted as a measure of the number of variances that would have to be granted by state authorities. Under the two policy options, both low sulfur coal and scrubbing industries have a rapid increase in utilization from 1975 to 1978. After this time the demand for scrubbers levels off. Utilization of low sulfur coal proceeds at about the same rate for both policies since supplies are constraining. Scrubber utilization is about 40% higher for SIP regulations than for the NAAQS and the annual expenditures for compliance are about 35% higher.

The effects of delay are dependent on the nature of the policies being considered. If the SIP policy is delayed two years from 1975 to 1977, noncompliance increases by 58% in 1980 and is still 52% higher in 1982. But if the New Source Performance Standards (NSPS) are separated from the SIP, so that the NSPS are enforced in 1975 while the SIP policy is delayed two years, then noncompliance in 1982 is only 38% higher. However, the amount of FGD utilized remains the same; changes in compliance reflect varying utilization of LSC that is constrained in turn by the supply-demand relationships. On the other hand, a two-year delay in the less stringent NAAQS policy raises noncompliance in 1982 from 2% of regional capacity to 6%. If, as was described above, the new source standards are enforced in 1975, then delay of the NAAQS to 1977 makes no change in ultimate compliance in 1982. This is simply due to the fact that long-run LSC supplies are adequate to meet demands occasioned by the NAAQS, but not SIP, policy. As long as some LSC demand is created in 1977, the supply growth of Western coal will be initiated soon enough to generate LSC quantities that are adequate to eliminate the fuel supply constraint under the NAAQS policy in 1982.

Thus it can be seen that simply delaying enforcement of a policy shifts the response and compliance later in time, but not linearly. Delays not involving new sources allow supplies of Western coal to develop based on new source demand; thus the rate of utility compliance once the standard is enforced is accelerated. The initial enforcement of new source standards will initiate the growth of both the LSC and the FGD industries. This effect is most important to the scrubber industry.

In each policy scenario analyzed, scrubbers are invariably at least slightly more expensive than low sulfur Western coal. This cost relationship indicates that scrubbers are utilized only when there is simultaneous enforcement of an emission limitation and a scarcity of low sulfur coal. Scrubber utilization always seems to reach a plateau within five years of initial utilization; after that, scrubbers are underutilized with respect to potential supply. Western coal utilization, on the other hand, is guided through the initial years of policy enforcement by the rate of growth of production. If a program of air quality improvement is phased-in over several years, demand for LSC will be immediate and strong. If, in any year of the analysis, the available LSC is used up, then some plants are assigned scrubbers in spite of their slightly higher cost. Thus, if the phasing-in of air quality standards is very gradual, it could well result in almost all compliance being accomplished with clean fuel. Prompt enforcement of broad and stringent standards will favor the scrubber industry. This conclusion is reinforced by the fact that scrubber costs are based on a fully developed technology. If there is such a delay in policy enforcement, the scrubber industry may not progress technologically as anticipated sales are postponed.

Simulation of an intermittent control policy for rural plants is shown in Fig. 6.9. Here, all existing plants in rural areas were exempted from using control devices or any significant amount of low sulfur fuel until 1980. These plants were then subjected to the National Ambient Air Quality Standards. Urban plants were subjected to the emission limitations of the SIPs; new plants, wherever located, were governed by the new source standards. In terms of compliance rates and utilization of FGD and LSC, the response to this policy falls between SIP implementation and the NAAQS policy.

A final observation with regard to these analyses has to do with the economic impact on the electric utilities in the Midwest of the various policy options. The annual compliance costs in constant 1974 dollars for the SIP policy range from $100 million to $1.2 billion, or over $16/yr/kw in compliance. Rural intermittent control reduces these costs by 10% and 14%. Enforcement of ambient air quality standards instead of SIPs reduces these costs by 22% and 32%, respectively. Almost uniformly the policies analyzed caused an increase in costs of power generation of 2-3 mills/kw-hr. This represents a 10-20% increase in current power production costs.

6.2 PRICE ANALYSIS

The preceding analysis indicated a large excess demand for low sulfur coal that could lead to an inflationary spiral, which would alter prices and drive up scrubber utilization. Any relative cost change that would improve the competitive position of FGD could greatly increase FGD utilization. In all the policy options analyzed in Sec. 6.1, FGD supply rapidly outgrows demand. The potential for greater utilization is large, and the price change required to realize it should be analyzed. The scenario chosen for price analysis was the enforcement of New Source Performance Standards (NSPS) and primary air quality standards (NAAQS) in 1977. This policy was analyzed with no variation allowed from a strictly least-cost response in order to isolate the effects of cost changes. That is, the criterion, that up to 15% deviation from least cost would not affect a control decision when availability is limited, was eliminated. This 15%, as is examined further in the analysis, simulates the cost overrun that a utility might accept in order to avoid fines or litigation costs. Leaving out this differential was necessary for a clear insight into the effects of price changes.

The price of LSC was increased 5-40% from the base level used in the policy analyses in Sec. 6.1; this was equivalent to a parallel decrease in FGD price. Figures 6.10, 6.11, and 6.12 show noncompliance in the year 1982 as well as FGD and LSC utilization by that time for a range of price variations. (Note that these Mw of FGD utilized do not equal Mw of capacity; the amount of FGD needed to "cover" each utility plant is dependent on the severity of the emission standard that must be met.)

Only a 10% change in relative prices is needed to bring the regional utility system into compliance by 1982 (see Fig. 6.12). FGD costs are only slightly higher than the costs of LSC, and thus only a slight change is needed to dramatically increase the utilization of FGD. At a 10% price change, the excess demand for LSC in 1982 is reduced to zero, and compliance with the policy scenario is essentially complete. Any price change beyond this 10% point will not improve ultimate compliance in 1982. Greater relative price changes cause increasing amounts of FGD to be substituted for LSC as can be seen in Fig. 6.10, with the supply of FGD being adequate for demand occasioned by even a 40% price change.

Of course any relative price change beyond the 10% turning point will speed compliance, but there is a point of diminishing returns. If the relative price change is too extreme, then the rate of compliance will be hindered by the lack of enough scrubbers to meet demands. Although the ultimate compliance by 1982 will be essentially complete beyond a 10% change, the compliance by, say, 1980 will only worsen if the relative price change is greater than 25%. Between 10% and 25%, the rate of compliance is not very sensitive to the relative price changes.

Although there could be unforeseen cost breakthroughs in FGD technology, the price estimates in this analysis are generally optimistic. FGD prices could be affected through pricing policies such as fines, subsidies, or taxes. It should be noted that capital charges account for 50-55% of annual compliance costs if a plant uses FGD to meet emission standards. Comparatively, compliance by use of LSC involves capital charges amounting to only 5-10% of total annual compliance costs. The conclusion is obvious that FGD costs and utilization are crucially dependent on what electric utilities must pay for capital.

The policy implications of the cost sensitivity for the Midwest are profound. Only about a 10% decrease in relative cost is needed to make FGD viable in this region. A cost decrease of 35% relative to LSC would reduce by over half the use of LSC in the Midwest utility market. At stake are not only air quality goals, but also the large coal industry producing high sulfur coal in three of the states of the study region. The regional benefits of preserving this coal industry should be considered in a decision to stimulate adoption of FGD.

6.3 AVAILABILITY ANALYSIS

An analysis was conducted of the effects of LSC availability increasing more rapidly than was assumed in the preceding analysis. This was done by causing the supply of type 2 LSC to be 125% higher in 1977 and to grow by 50% annually to a level that was 388% above the previously projected supply. This growth would be produced by less efficient strip mining techniques in Wyoming and Montana. It is believed that the price of coal from such sources is essentially independent of supply, and thus the cost to utilities was not increased. This is not the cheapest Western coal, nor is it the most expensive. These small strip mines use readily available equipment for mining, and thus may not be subject to the same constraints on expansion as are both large surface mines and underground mines that utilize specialized equipment. The large mines are not expected to be able to grow any more rapidly than the projections used in the policy analyses. The only way that the smaller mines could expand production significantly would be through the diversion of equipment and labor from other industries. The 50% annual rate of growth is a very optimistic one.

By 1982, under this assumption the 68 M tons produced by small surface mines would dwarf other sources of Western LSC. The policy scenario was, again, the 1977 enforcement of both NSPS and the NAAQS. The increased amount of type 2 LSC raised the total available to the utilities from 96.8 M tons by 1982 to 151.1 M tons -- an increase of 56%. The results are predictable; by 1982 LSC utilization rises from 96.8 to 118.1 M tons and the capacity in compliance with standards from 85,530 to 94,250 Mw. This large increase in available LSC eliminates the excess, unsatisfied demand for clean coal by 1981.

It should also be noted that in either case the amount of FGD utilized is about 15,000 Mw. A closer look at the individual plant responses shows why the use of FGD does not decline. It turns out that in order to comply with this policy scenario, only existing plants subject to meeting the NAAQS utilize FGD. New power plants subject to the more stringent NSPS and unable to find low cost high sulfur coal, which existing power plants are utilizing, find it at least slightly cheaper to use Western LSC. The allocation of scarce resources in the policy analysis gives priority to new plants that must comply in order to be built and operated. Thus, the additional coal is used by the new, high priority plants and the rate of compliance is improved. However, for existing plants lower down on the priority ladder, even the large increase in coal supply does not come soon enough for them to avoid FGD. Since the 15% cost differential simulates enforcement, these plants are assigned the slightly more costly FGD in the earlier years of the analysis.

It can be concluded that the utilization of FGD is not sensitive to the long-run supply of LSC. The rate of compliance is directly related to LSC availability. The projected supply of FGD is more than adequate to meet demands even at half the allowed growth rate for the scrubber industry. Even with large relative price changes on the order of 30-40%, the long-run supply of FGD is adequate. Only an initial, three-year lag in supply constrains the utilization of FGD.

6.4 ALTERNATIVE EMISSION LEVELS

In order to guide policy making, it is helpful to consider the regional utility response as a function of permitted emission levels. A simple uniform emission standard was applied to all existing power plants in the region with enforcement beginning in 1977. New plants were covered by the New Source Performance Standards (NSPS). The standard was varied from an extremely strict 1.21 lb SO_2/MBtu to a generous 3.50 lb SO_2/MBtu. The lower bound of 1.21 lb SO_2/MBtu precludes use of high sulfur coal except for a small amount blended with deep mined Western coal.

Figures 6.13-6.15 display the results of varying emission standards. The utilization of LSC by 1982, as shown in Fig. 6.13, does not fall off until the standard is lowered to 3.00 lb SO_2/MBtu or greater. The remaining unsatisfied demand falls with rising emission limits, but only a 3.00 lb SO_2/MBtu standard or greater gives a clean fuel surplus by 1982. Scrubber utilization by 1982 (Fig. 6.14) stays at around 17,000 Mw for all emission limits. The plants using FGD are being compelled to do so by enforcement even though LSC is slightly cheaper. This utilization reaches a plateau by the fifth year as FGD supplies increase rapidly and go far beyond utility demand. The available supply in the first few years of enforcement, when both options are supply constrained, can be spread over more power plants as emission standards are relaxed. This is consistent with requiring a plant to remove only enough SO_2 to just meet the legal emission rate. The capital cost of FGD is sensitive to the required removal of sulfur so the cost competitiveness of FGD seems to improve as emission limits are relaxed.

Figure 6.15 shows the time path to compliance by displaying the total plant capacity not in compliance in each year. It can be seen that significant improvements in compliance come only when the emission standard is relaxed to 2.5 lb SO_2/MBtu or higher. If 1982 is the target year for complete compliance, 3.00 lb SO_2/MBtu is as high as the standard need be.

6.5 STRICT ENFORCEMENT OF POLICIES

The preceding policy analysis is an economic analysis of the utility response to various control policy options. The analysis assumes economic choice on the part of utilities without strict enforcement. That is, variances are granted to electric utilities if the desired control option (generally LSC) is not available and the other control option (generally FGD) has a cost penalty of 15% or more over the desired control option. It is desirable to investigate the cost and effectiveness of strict enforcement of standards, subject only to availability.

In this analysis, electric utilities are required to choose a control option if it is available. In the case of NSPS and NAAQS enforced in 1977, the utilization of FGD in 1982 increases from 14,000 Mw to 24,000 Mw. For the NSPS and SIP applied in 1977, the utilization of FGD in 1982 increases from 20,000 Mw to 40,000 Mw. Strict enforcement gives compliance by 1981. Since compliance is so crucially dependent on the use of FGD, only an extremely vigorous program of installation and experimenting with FGD will result in timely compliance. The increased costs reach nearly \$700 million/yr for the region by 1982 to enforce the NAAQS; enforcement of SIP regulations implies increased annual costs of nearly \$1200 million by 1982.

6.6 SENSITIVITY ANALYSIS

Because of the predictive nature of the cost estimates utilized in this study, it is desirable to investigate the sensitivity of the results to these various cost factors. Two factors, system costs and boiler conversion costs, are studied.

6.6.1 System Costs

The cost of utility responses includes an estimate of system costs. These are costs incurred not at the particular plant being analyzed but at other plants within the interconnected utility system because of the control strategy being considered for the particular plant. These costs are essentially the cost of providing more energy from other units, or if necessary, adding other units to keep the system reliability constant. This system cost is most severe for FGD because of scrubber reliability problems.

Ignoring these system-wide costs increases FGD utilization by 45-65% with resulting improvement in the rate of compliance. Using as an example the case of SIP enforcement in 1975, ignoring system costs will increase FGD installation by 1982 from 19,740 Mw to 33,030 Mw. Noncompliance falls from 14,670 Mw in 1982 to 180 Mw. LSC utilization falls only slightly, constrained through most of the years by availability. If the system costs are ignored in another example, 1975 NAAQS, the increase in FGD utilization is also large -- from 13,830 Mw in 1982 to 20,070 Mw. However, the above is somewhat unrealistic as these system costs could be reduced, but not eliminated.

If the reliability of scrubbers were to be improved so that they increased the forced outage rate of a power plant by 0.05, instead of the expected 0.10, then system costs for this control option would be reduced 28%. The complete dissociation of scrubber operating reliability from that of the power plant by means of flue gas bypasses would decrease the FGD system cost by 57%. These lower system costs improve the competitive position of FGD versus LSC and result in greater utilization of scrubbers, and thus, more rapid compliance with policy. Specifically, for SIP enforcement beginning in 1975, improving scrubber reliability increases utilization nearly 35%; decoupling the scrubber reliability increases utilization over 60%. The attendant improvements in compliance by 1982 are 10% and 18%, respectively. Somewhat lesser increases result if the policy enforced in 1975 is the less stringent NAAQS.

6.6.2 Boiler Conversion Costs

Included in the cost of LSC utilization is the expense of converting any existing boilers to burn Western coal with its higher ash content and higher ash fusion temperature. These costs are especially high for the many wet-bottom boilers that were designed to use Midwestern high sulfur coals.

The costs used are \$35/kw for wet-bottom boilers and \$10/kw for dry-bottom. These costs are based on a January 1973 Staff Study by the Office of Emergency Preparedness.[14] The fraction of each plant that is of wet- and dry-bottom design is used in calculating conversion costs, which are then annualized over 15 years at the same rate used for FGD capital costs. No conversion charges are assessed against new plants.

The simulation of utility response is not very sensitive to this cost. Two strategies were analyzed with the conversion costs reduced by half. In the case of SIP enforcement in 1975, the ultimate use of FGD declines by only 7% from 19,740 Mw to 18,450 Mw in 1982. LSC utilization remains supply constrained, and therefore, compliance is poor. But in the case of 1975 enforcement of the NAAQS with reduced conversion costs, the use of FGD declines 12% from 13,830 Mw in 1982 to 12,190 Mw. With this policy, supplies of LSC are adequate to insure virtually complete compliance by 1982.

Thus, sensitivity to the boiler conversion costs will be more apparent when the policy is not so strict that LSC supplies are inadequate throughout the ten-year simulation period. This is borne out by noting that the cost models show, for base load plants, that the conversion cost of wet-bottom boilers is only 9-10% of the total annual cost of using LSC. For dry-bottom boilers, it is only 3-4%.

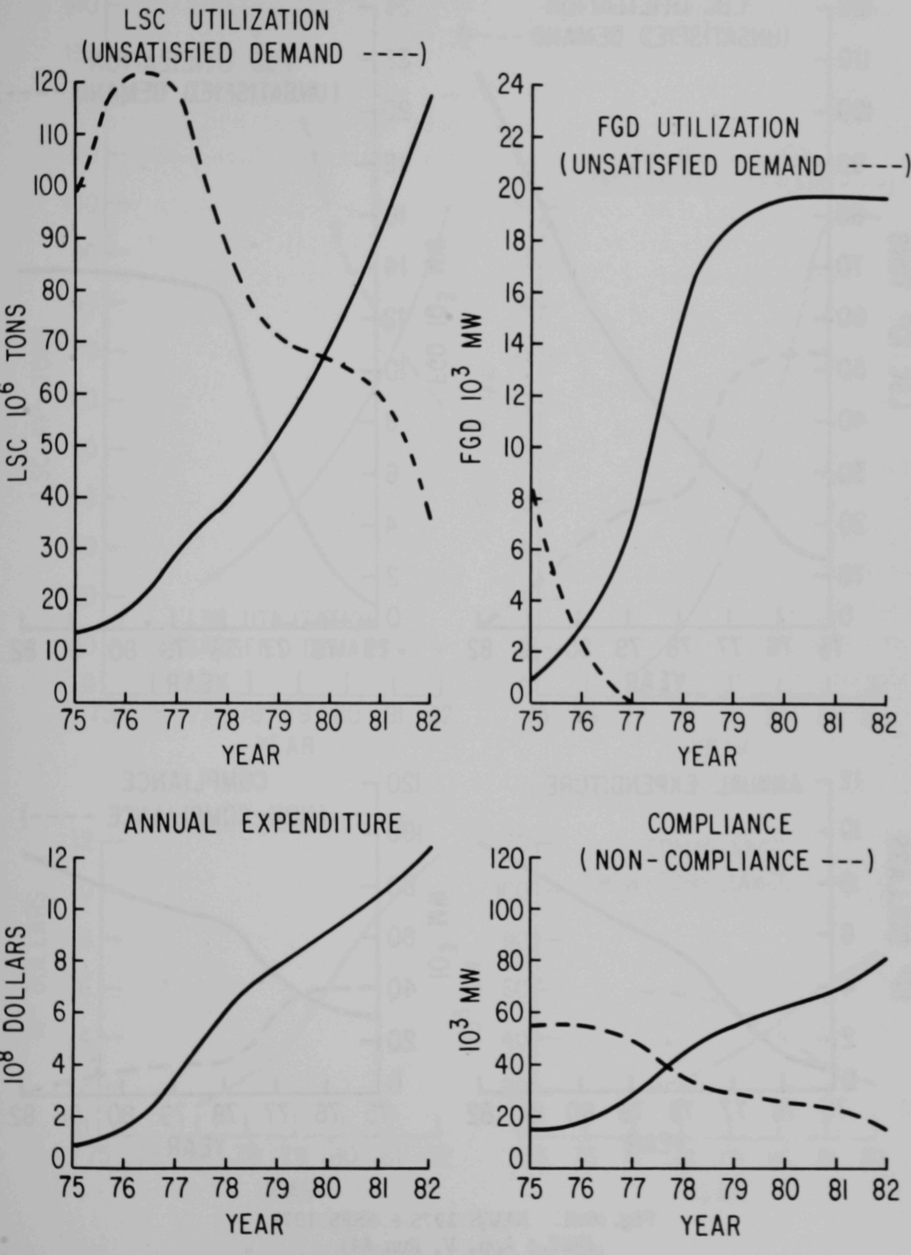

Fig. 6.1. SIP 1975 - NSPS 1975
(Ref.: App. V, Run #10)

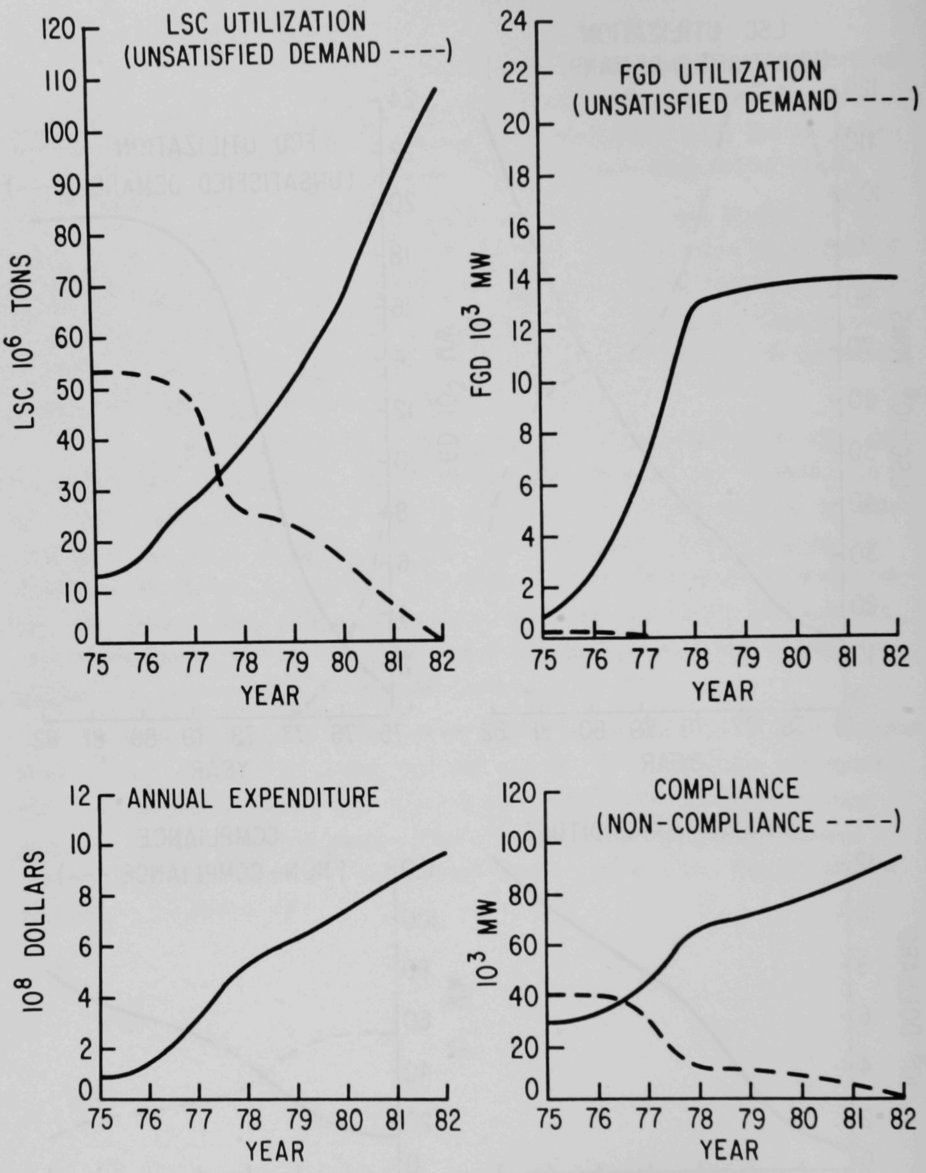

Fig. 6.2. NAAQS 1975 - NSPS 1975
(Ref.: App. V, Run #4)

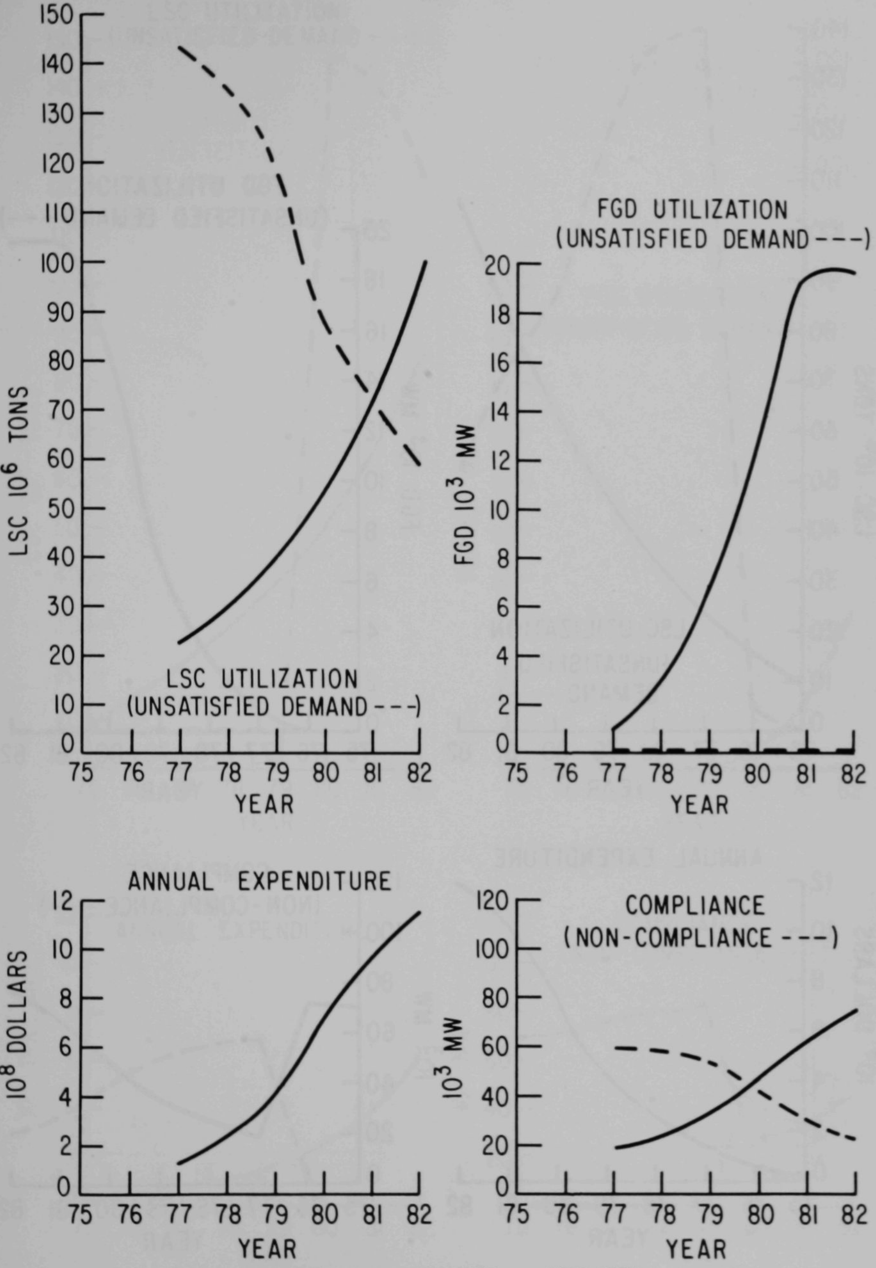

Fig. 6.3. SIP 1977 - NSPS 1977

(Ref.: App. V, Run #29)

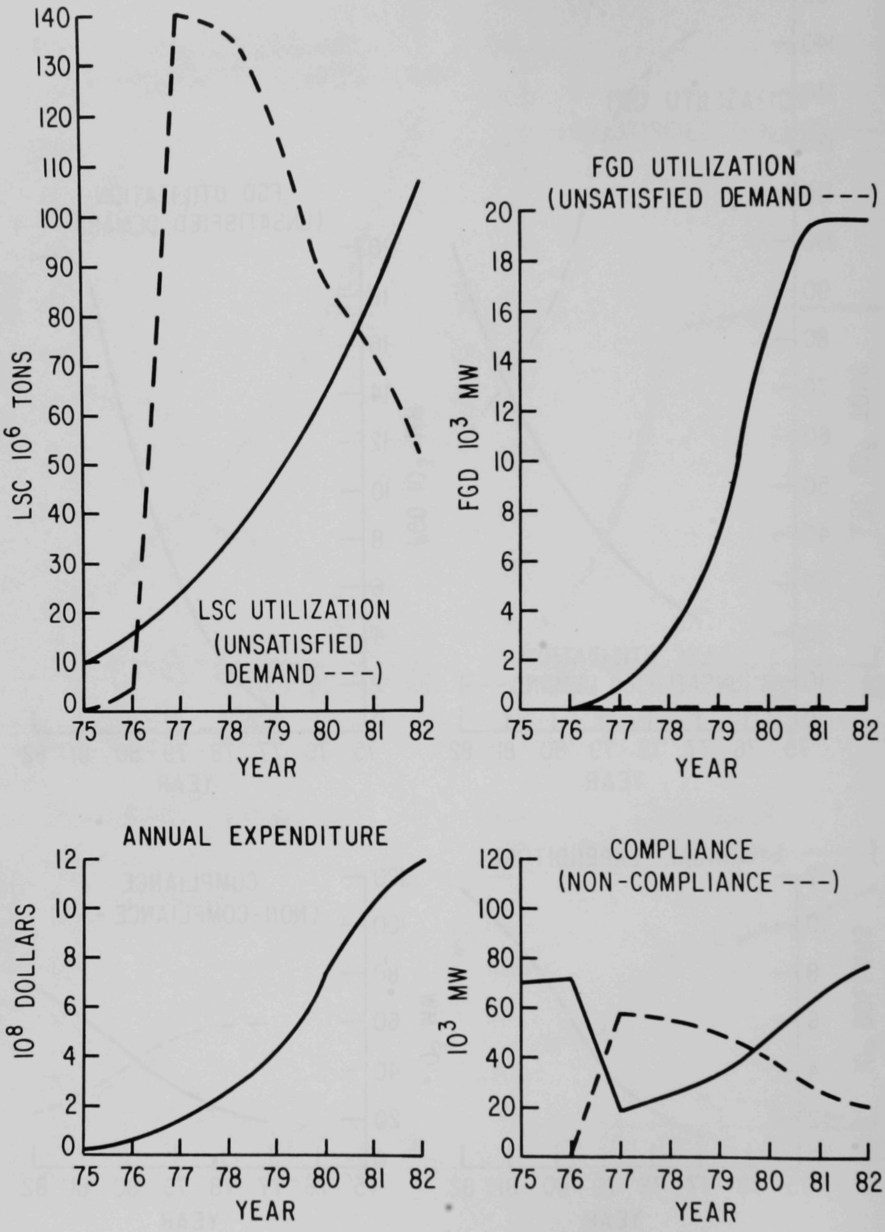

Fig. 6.4. SIP 1977 - NSPS 1975

(Ref.: App. V, Run #2)

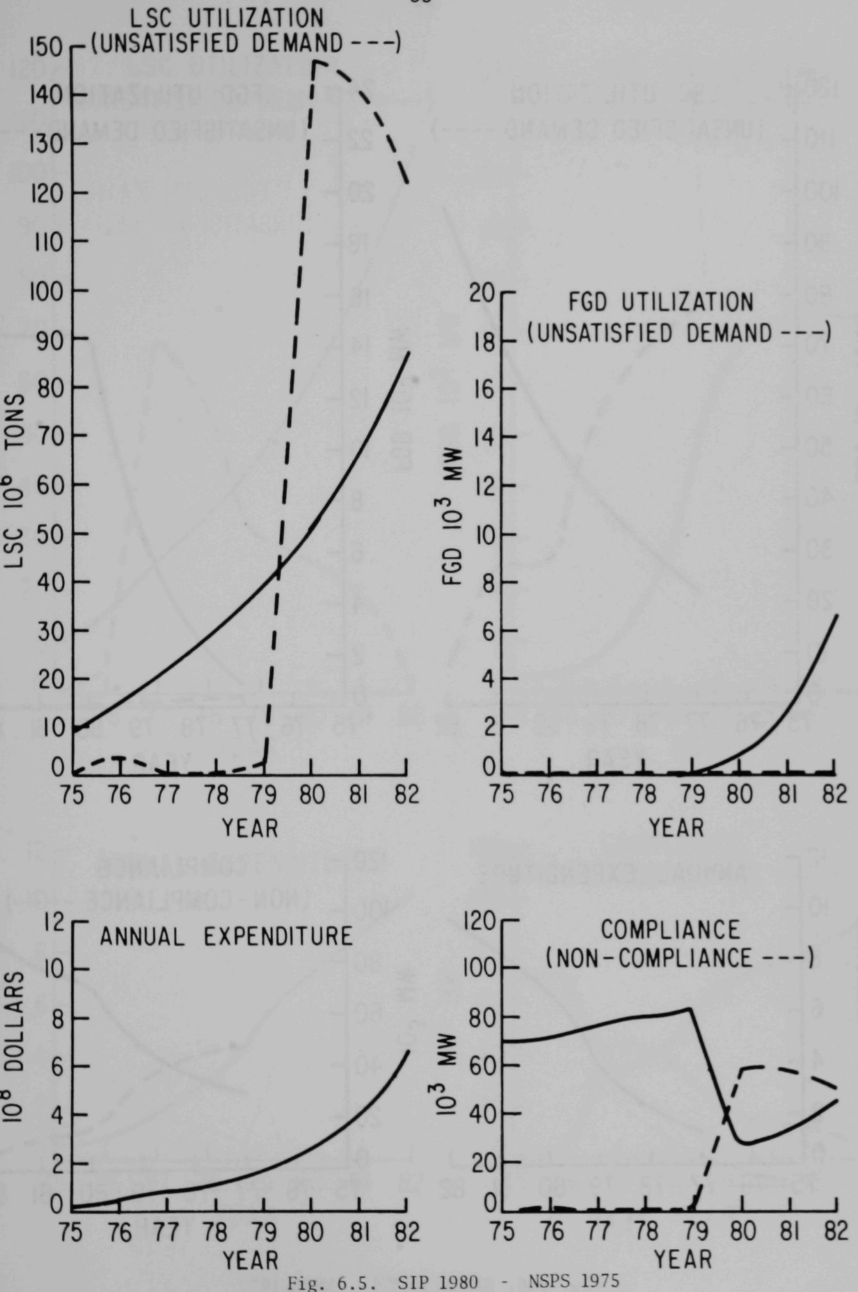

Fig. 6.5. SIP 1980 - NSPS 1975

(Ref.: App. V, Run #3)

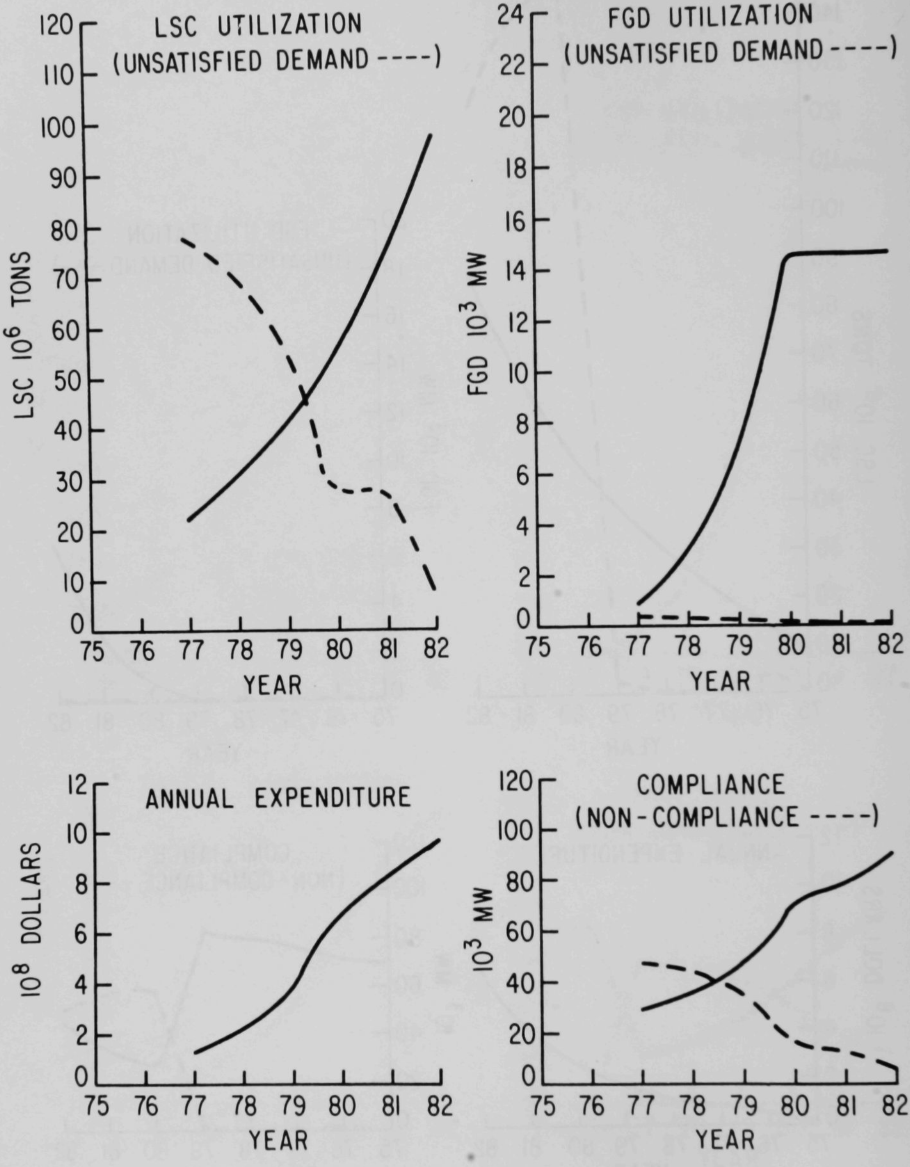

Fig. 6.6. NAAQS 1977 - NSPS 1977

(Ref.: App. V, Run #6)

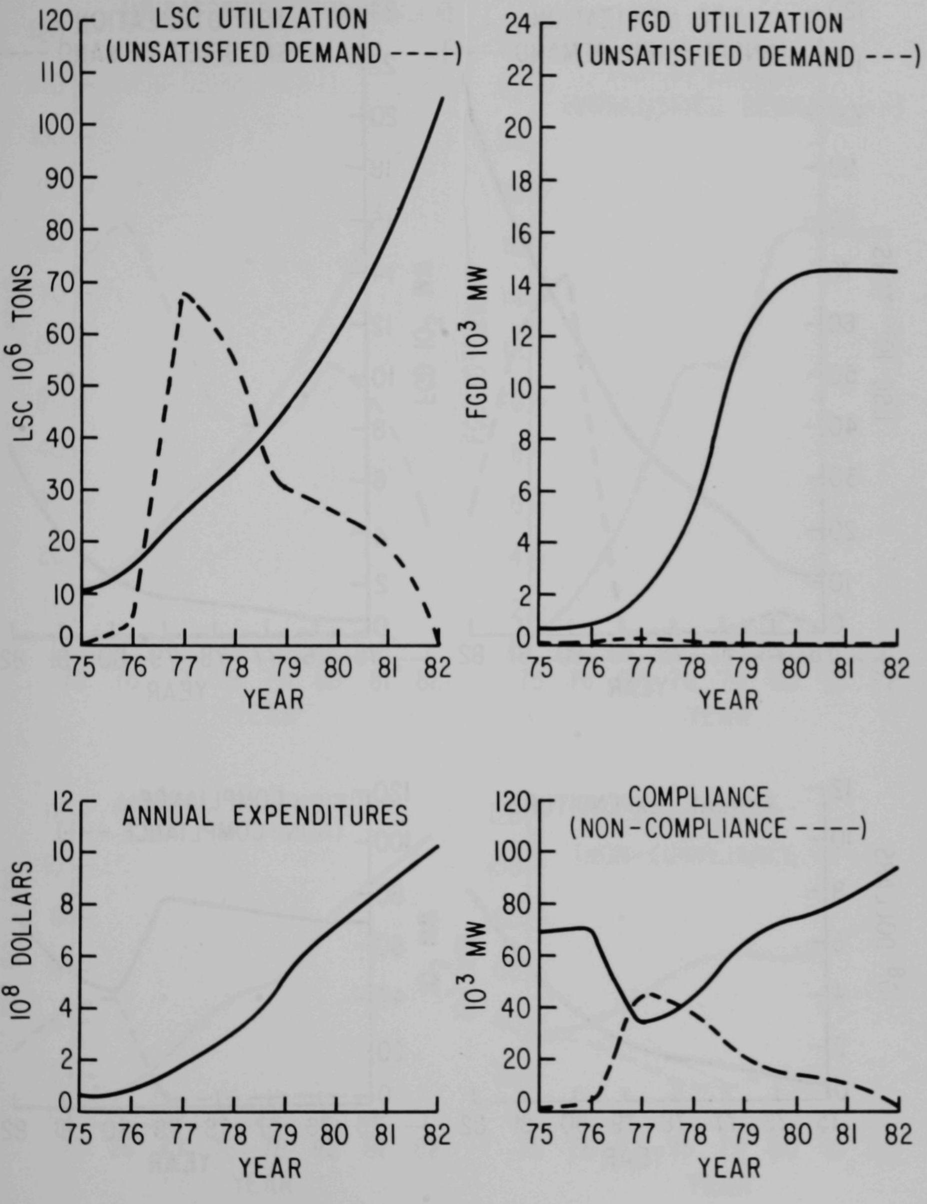

Fig. 6.7. NAAQS 1977 - NSPS 1975

(Ref.: App. V, Run #5)

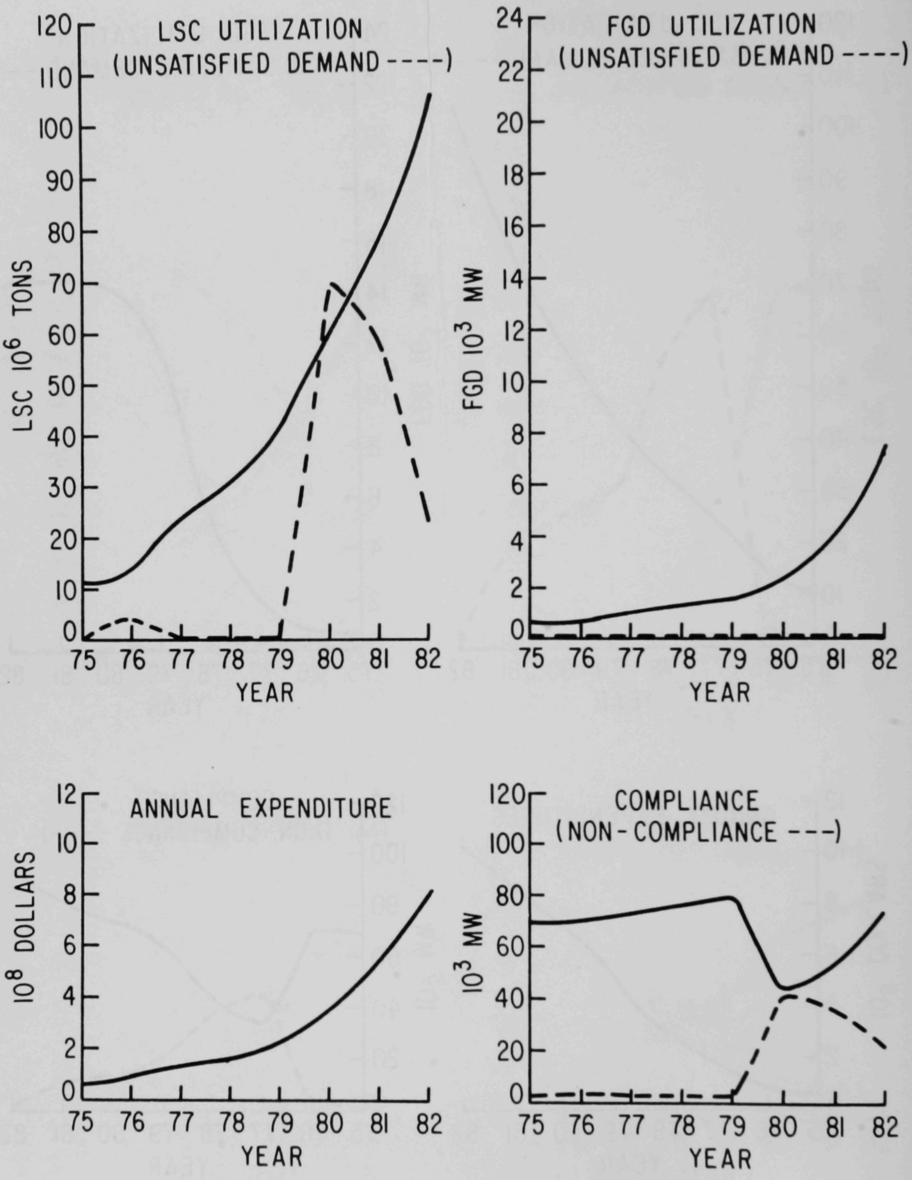

Fig. 6.8. NAAQS 1980 - NSPS 1975

(Ref.: App. V, Run #7)

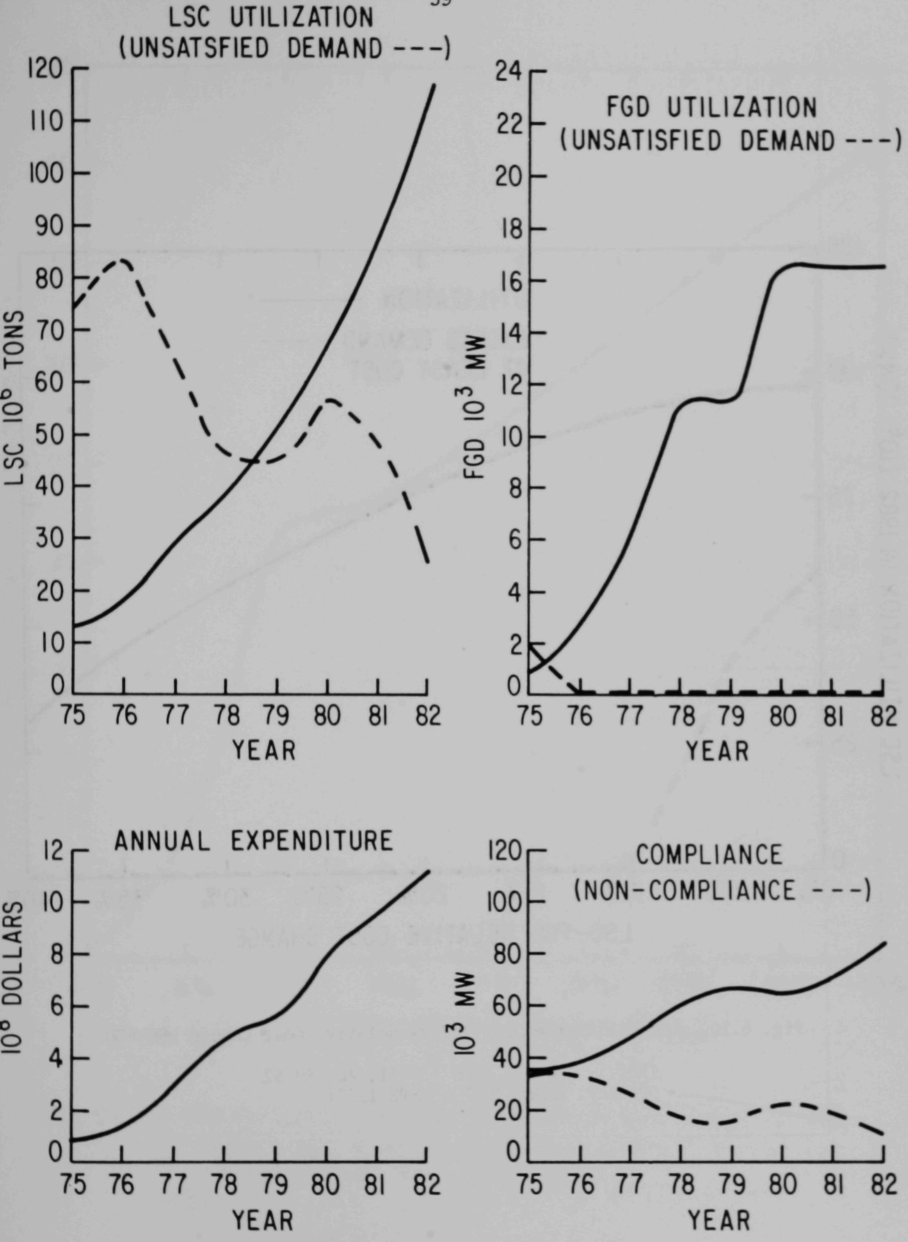

Fig. 6.9. SIP 1975 - NSPS 1975
Rural IC to 1980 then NAQS

(Ref.: App. V, Run #12)

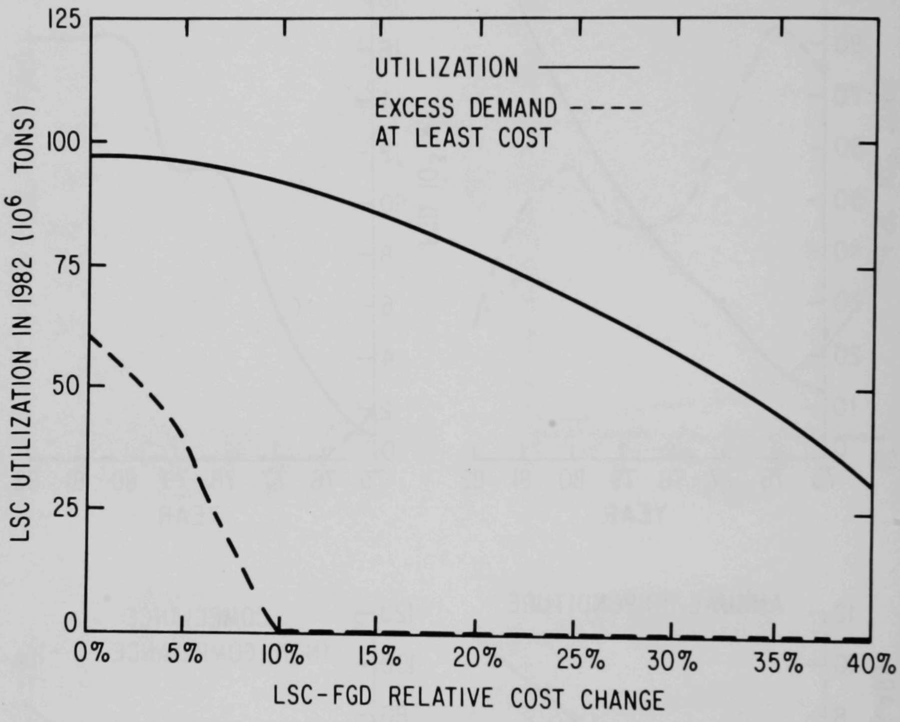

Fig. 6.10. LSC Utilization in 1982 vs Relative Cost Change LSC-FGD

(Ref.: App. V, Runs #37-41, 46, 50-52
Policy: NAAQS 1977 - NSPS 1977)

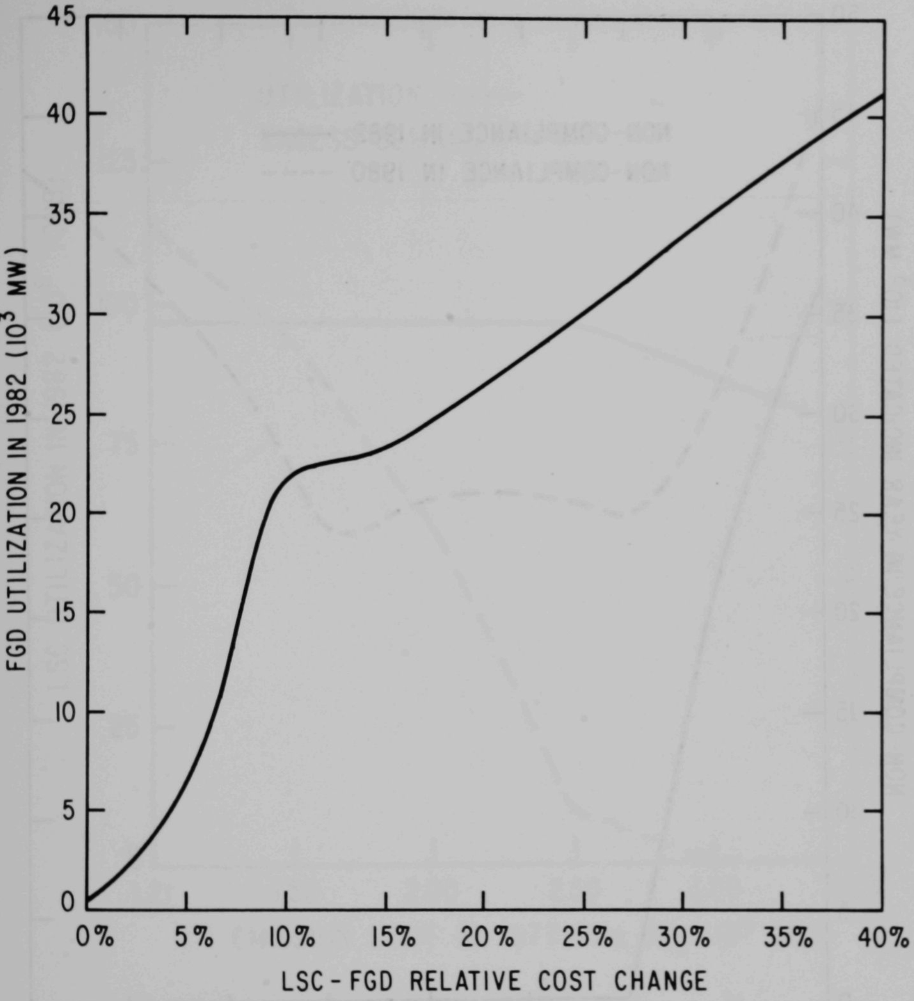

Fig. 6.11. FGD Utilization in 1982 vs. Relative Cost Change LSC-FGD
(Ref.: App. V, Runs #37-41, 46, 50-52
Policy: NAAQS 1977 - NSPS 1977)

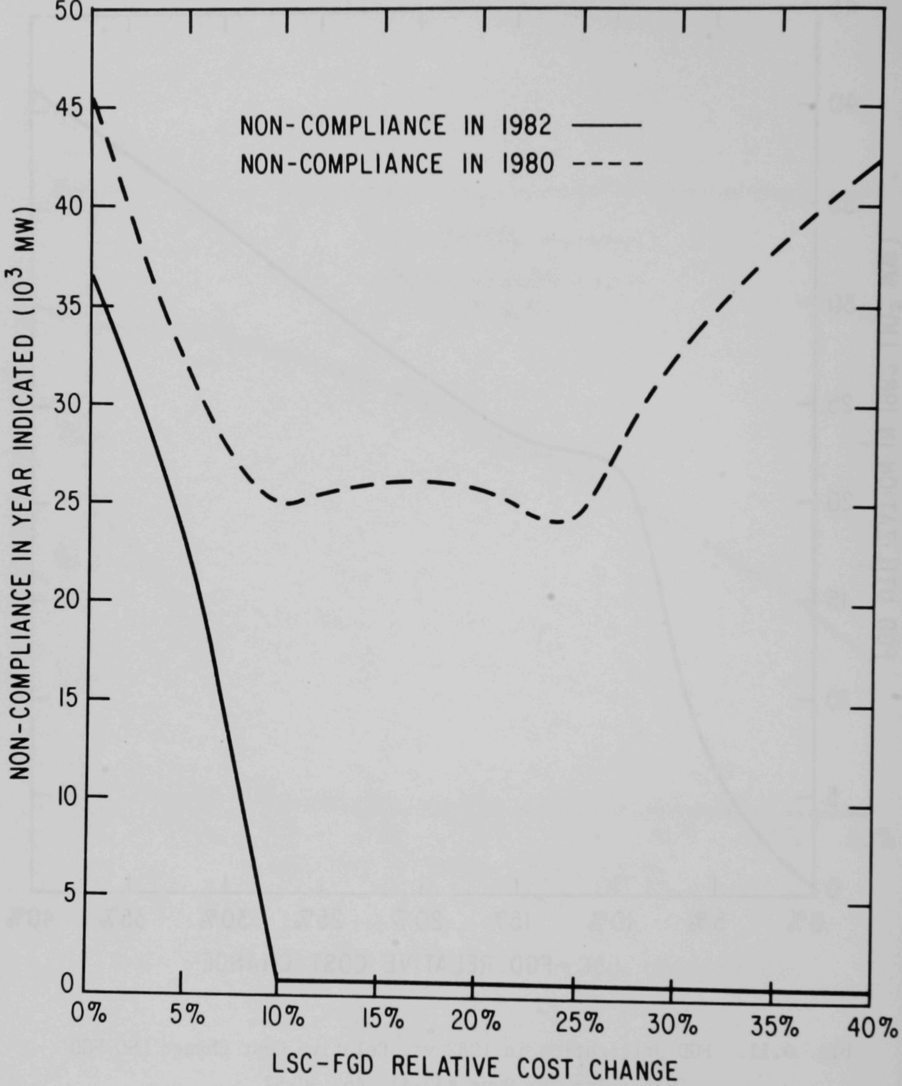

Fig. 6.12. Non-Compliance in 1980 and 1982 vs Relative Cost Change

(Ref.: App. V, Runs #37-41, 46, 50-52
Policy: NAAQS 1977 - NSPS 1977)

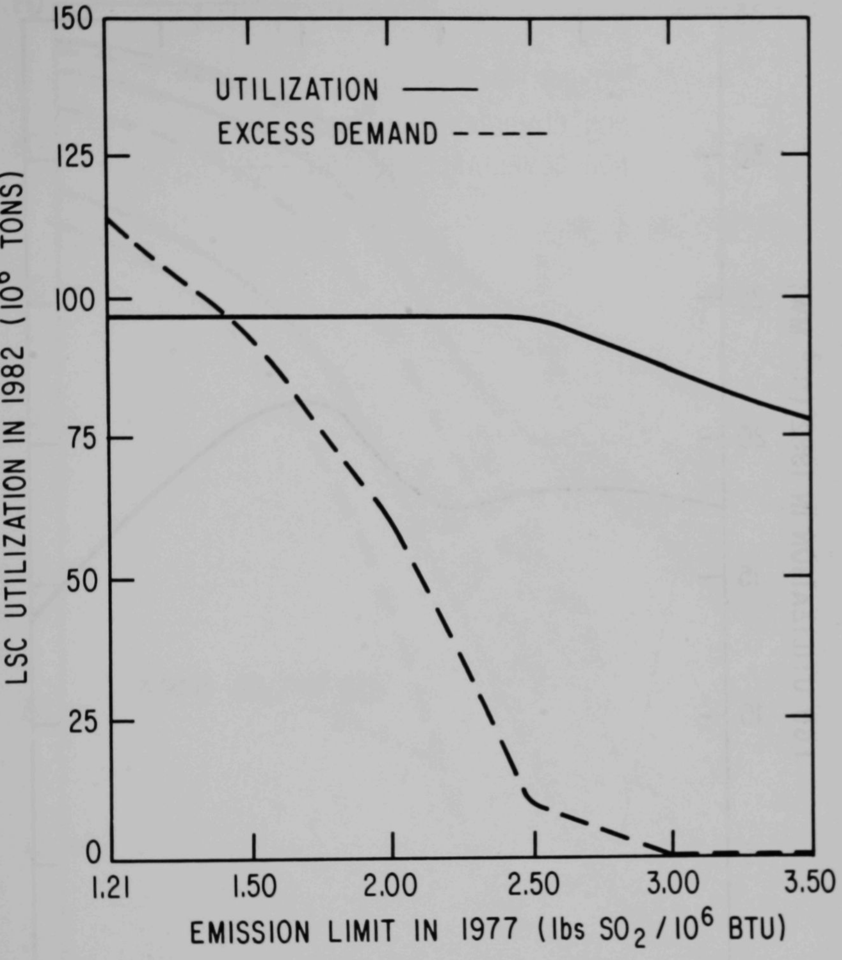

Fig. 6.13. LSC Utilization in 1982 vs Emission Limit in 1977
(Ref.: App. V, Runs #31-36)

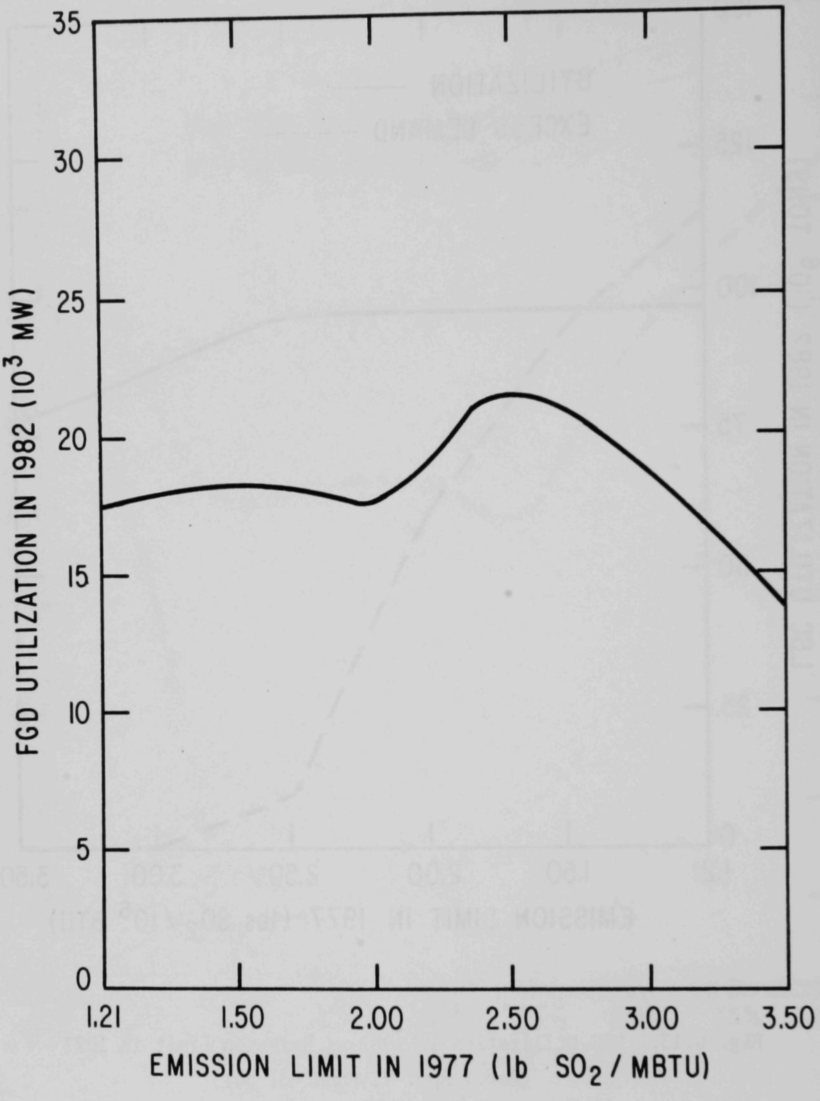

Fig. 6.14. FGD Utilization in 1982 vs Emission Limit in 1977

(Ref.: App. V, Runs #31-36)

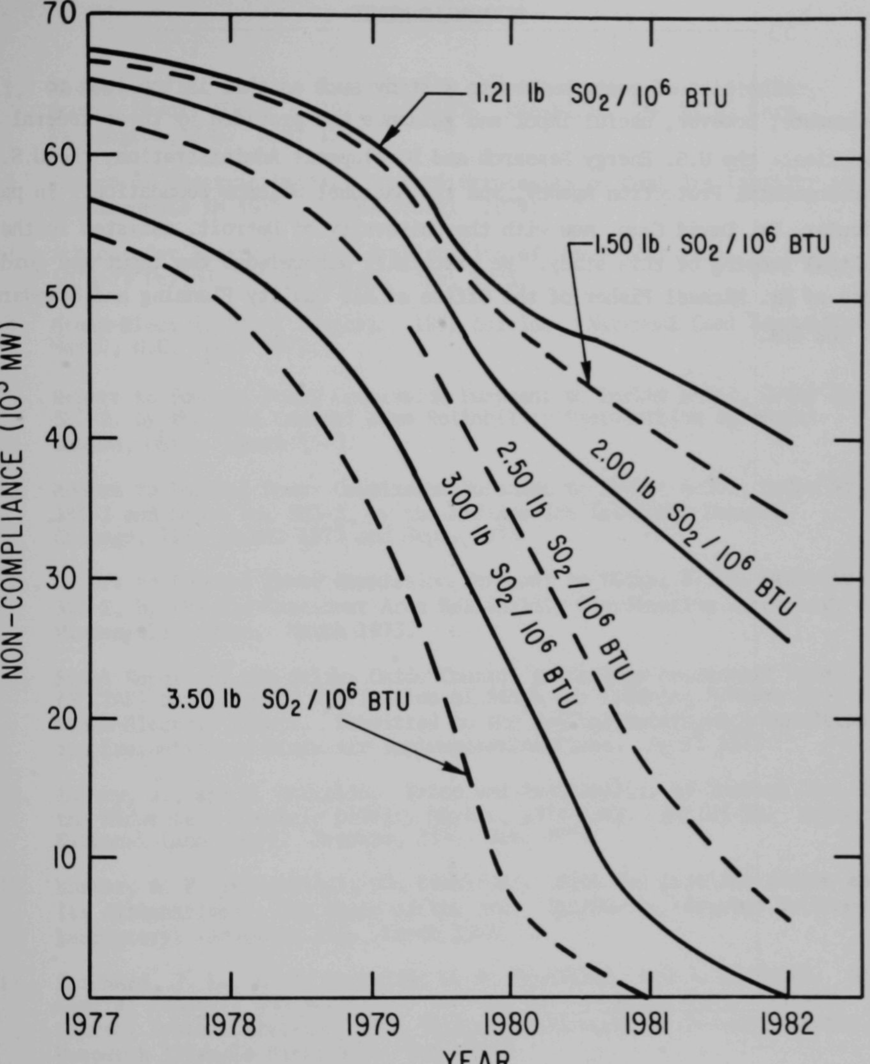

Fig. 6.15. Non-Compliance vs Time for Emission Limits in 1977

(Ref.: App. V, Runs #31-36)

ACKNOWLEDGMENTS

The list of contributors to a study such as this is too long to enumerate; however, useful input and guidance was provided by three federal agencies: the U.S. Energy Research and Development Administration, the U.S. Environmental Protection Agency, and the National Science Foundation. In particular, Dr. David Camp, now with the University of Detroit, assisted in the initial scoping of this study. We gratefully acknowledge the input and guidance of Mr. Michael Fisher of the Office of Air Quality Planning and Standards in the EPA.

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APPENDIX I. POLICY ANALYSIS MODEL (PLAN)

This appendix contains a more detailed documentation of the computer simulation code (PLAN) written to analyze emission control strategies for electric utilities.

PLAN is written in FORTRAN and uses about 200K of computer storage. It runs in approximately 30 seconds on the IBM 370/195.

The sections included in this appendix are as follows:

A. An overall flow diagram of the PLAN policy analysis model.

B. Description of the input data required to execute the PLAN model.

   1. Group data,

   2. Low sulfur coal cost and supply data,

   3. Scrubber supply data,

   4. Strategy data,

   5. Plant and boiler data.

C. A sample problem using a strategy of SIP in 1975 and NSPS in 1975.

   1. Input for sample problem,

   2. Plant data base input,

   3. Output for sample problem,

   4. Optional output.

D. Definition of variables used in PLAN.

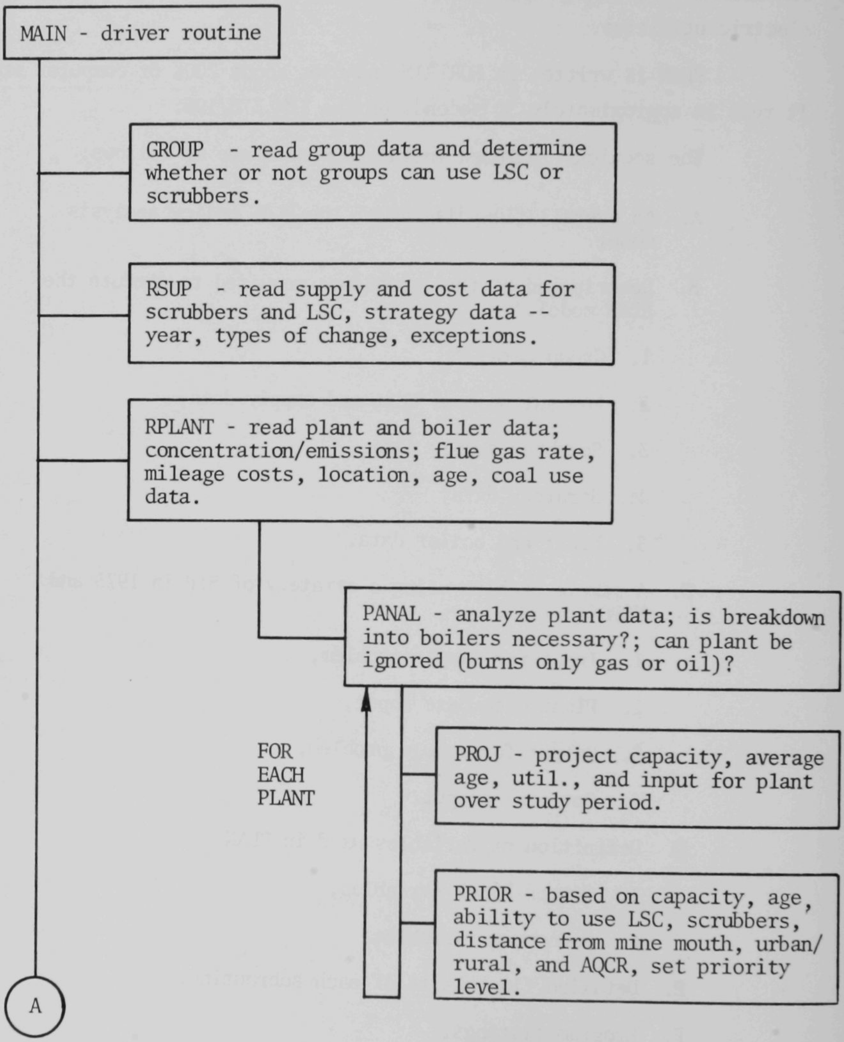
   1. Common block variables,

   2. Noncommon variables.

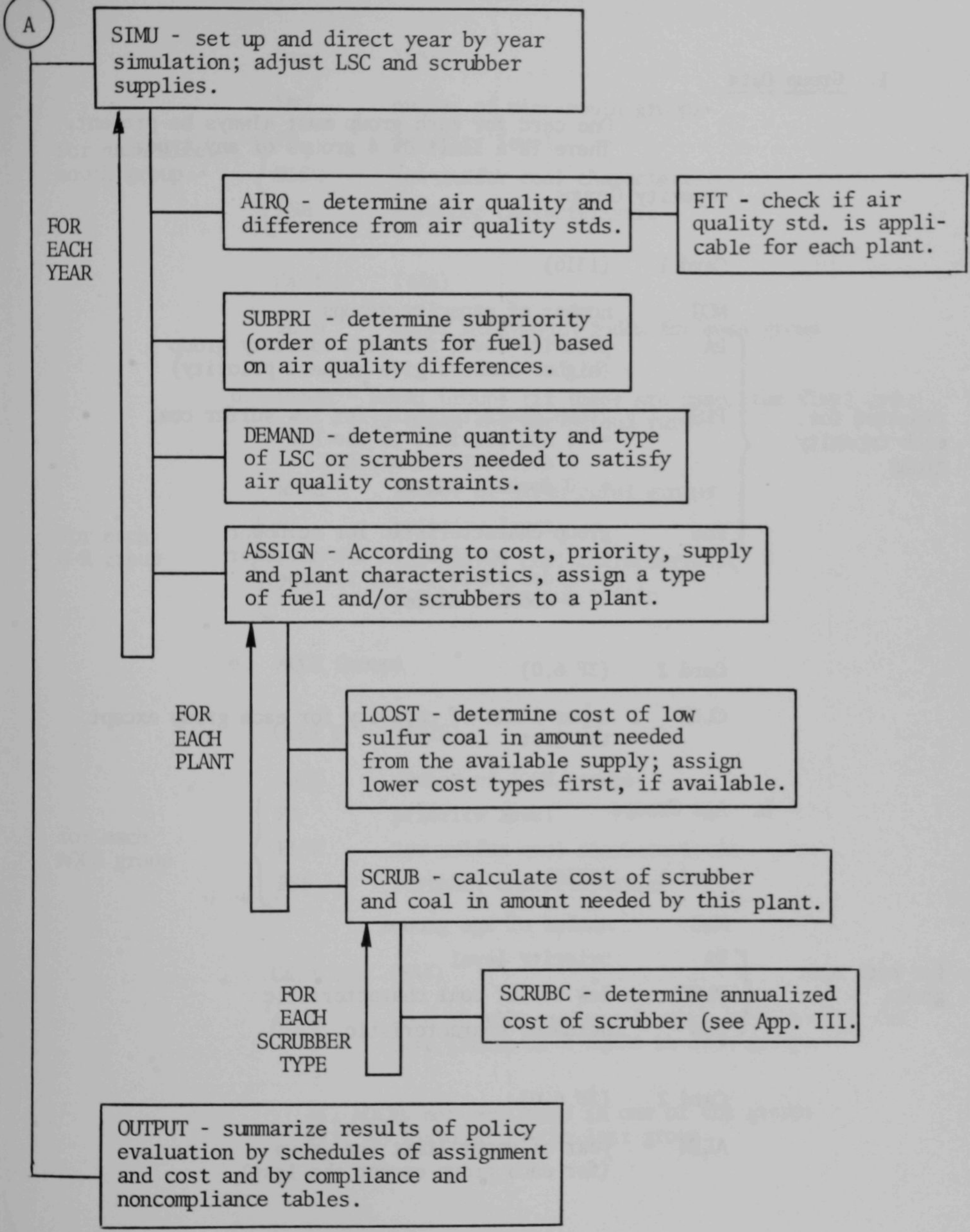
E. Detailed flow charts of each subroutine.

F. Program listings.

I.A. FLOW DIAGRAM OF POLICY ANALYSIS MODEL (PLAN)



I.A (Contd.)


A
SIMU - set up and direct year by year simulation; adjust LSC and scrubber supplies.
FOR EACH YEAR
AIRQ - determine air quality and difference from air quality stds.
FIT - check if air quality std. is applicable for each plant.
SUBPRI - determine subpriority (order of plants for fuel) based on air quality differences.
DEMAND - determine quantity and type of LSC or scrubbers needed to satisfy air quality constraints.
ASSIGN - According to cost, priority, supply and plant characteristics, assign a type of fuel and/or scrubbers to a plant.
FOR EACH PLANT
LCOST - determine cost of low sulfur coal in amount needed from the available supply; assign lower cost types first, if available.
SCRUB - calculate cost of scrubber and coal in amount needed by this plant.
FOR EACH SCRUBBER TYPE
SCRUBC - determine annualized cost of scrubber (see App. III.
OUTPUT - summarize results of policy evaluation by schedules of assignment and cost and by compliance and noncompliance tables.

I.B INPUT DATA DESCRIPTIONS

1. Group Data

One card for each group must always be present. There is a limit of 4 groups of any type.

a. Capacity Groups

Card 1 (13I6)

	NCG	number of capacity groups
repeated for each capacity group	PA	priority level for each capacity group (higher numbers give highest priority)
	PLSC	group characteristic for low sulfur coal = -1 not possible to use LSC = 1 desirable to use LSC = 0 doesn't matter
	PSB	group characteristic for scrubber = -1 not possible to use scrubber = 1 desirable to use scrubber = 0 doesn't matter

Card 2 (3F 6.0)

CLIM upper limit of capacity for each group except the last

b. Age Groups

Card 1 (13I6)

	NAG	number of age groups
for each age group	PA	priority level
	PLSC	low sulfur coal characteristic
	PSB	scrubber characteristic

Card 2 (3F 6.0)

ALIM year of upper limit for group (for each group except the last)

c. Mine-Mouth Groups

Card 1 (13I6)

	NMG	number of mine-mouth groups
for each mine-mouth group	PA	priority level
	PLSC	low sulfur coal characteristic
	PSB	scrubber characteristic

Card 2 (4I6)

MLIM upper mine-mouth index for each group

d. Urban - Rural Groups (if these are used, the first group is urban and the second rural)

	NURG	number of urban-rural groups
for each U-R group	PA	priority level
	PLSC	low sulfur coal characteristic
	PSB	scrubber characteristic

e. AQCR Groups

Card 1 (13I6)

	NAQG	number of AQCR groups
for each AQCR group	PA	priority level
	PLSC	low sulfur coal characteristic
	PSB	scrubber characteristic

Card 2 (8A4)

AQCR list of AQCR numbers in each group except the last (limit of 8 AQCRs in each group)

All AQCRs not mentioned in one of the groups will be included in the last group.

2. Low Sulfur Coal Cost and Supply Data

For up to 3 types of LSC in order of increasing cost.

Card 1 (6F6.0) (If this card is blank, proceed directly to scrubber supply data.)

Col.		
1-6	CMINE	production cost in $/ton
7-12	ESFACM	cost escalation factor for production; percent of real cost increase each year
13-18	CTRANS	transportation cost in $/ton-mile
19-24	ESFACT	cost escalation for transportation
25-30	BTULSC	Btu content -- Btu/lb
31-36	SULLSC	sulfur content; percent sulfur

Card 2 (I6, F6.0 I6, F6.0)

1-6	ISRT	type of supply relationship 1 = supply given year by year 2 = increase by percent of previous available supply 3 = increase by percent of previous demand
7-12	SPER	percent increase for types 2 or 3
13-18	IYRLS	initial year of availability
19-24	SUPLSI	initial supply (M-tons)

Card 3 (10F6.0) Needed only if ISRT = 1

1-60	SUPLSY	supply (M-tons) for each year after the initial year until the end of the study period

3. Scrubber Supply Data

Card 1 (I6, F6.0, I6, 2F6.0 5I6) Supply is cumulative and includes all scrubbers installed or available

Col.		
1-6	ISRTS	type of supply relationship 1 = supply given year by year 2 = increase in percent of available supply 3 = increase in percent of previous demand
7-12	SPERS	percent increase for types 2 or 3
13-18	IYRS	initial year of availability
19-24	SUPSI	initial supply (Mw)
25-30	ESFSC	cost escalation factor (percent)
31-60	STYPE (I)	types of scrubbers considered (up to 5 used) -- if more than one is considered, the minimum cost scrubber will be used for each plant 1 = limestone 3 = MgO 5 = caustic 2 = lime 4 = caustic, with thermal regulator

Card 2 (10F6.0) Needed only if IRSTS = 1

1-60	SUPSC	supply (Mw) for each year after the initial year until the end of the study period

4. Strategy Data

Card 1 (I6)

NSTRAT number of strategies for which cards follow

Card type 2 (I6, F6.0, 3I6, 3X, A3, 5X, A1, 4F6.0)

Strategy cards must be in chronologial order

Col.		
1-6	SYR	year in which strategy is applied
7-12	STAND	air quality standard (units depend on KIND)
13-18	KIND	kind of units for standard 1 = standard on primary emissions in lb SO_2/Btux10^6) 2 = standard on primary emissions in lb SO_2/day 3 = standard on concentration in $\mu g/m^3$ 4 = standard to be calculated
19-24	STA	state number if strategy applies to a particular state
25-30	SAQ	number of AQCRs to be specified in following card for strategy
34-36	SCOUN	county abbreviation if strategy applied to a particular county
42	SUR	a letter U or R if strategy applies to urban or rural plants
43-48	SCMIN	minimum capacity of plants to which strategy applies
49-54	SCMAX	maximum capacity of plants to which strategy applies
55-60	SAMIN	minimum of average year when plant was built to which strategy applies
61-66	SAMAX	maximum of average year built

Card type 3(10(3X, A3)) Needed only if strategy applies to particular AQCRs. Directly follows applicable strategy.

4-6 10-12, 16-18, 22-24, etc.	AQS	AQCR numbers to which strategy applies (as designated by SAQ)

5. Plant and Boiler Data

Cards are read from unit 8 instead of the regular card input on unit 5. Cards may be placed on disk or tape, or may be preceded by //FT08F001 DD * in the regular card input stream. Input data for each plant includes a plant card and corresponding boiler cards. After all plants are specified, a blank card follows. Cards of additional plant data for each plant are then included.

Card type 1 (Plant Card) (4A4, I2, 1X, I4, I2, A1, 2A3, 2I2, 2I1, F6.1, F8.1, F5.1, F8.5, F5.1, 3I3, I1)

Col.		
1-12	NAME	name of plant (12 characters)
13-23	CODE	FPC code number for the plant
24-25	STATE	state index number
26	URBAN	the letter U or R to indicate an urban or rural plant
27-29	AQCR	3-digit AQCR number
30-32	COUNTY	3-character county abbreviation
33-35	DAT	month and year in which plant was built; 2-digit month, 2-digit year (month may be omitted)
37	EXIST	1 = plant exists in initial study year, blank otherwise
38	MINEMO	mine-mouth indicator 1 = in coal producing area 2 = in coal producing county 3 = mine-mouth plant blank otherwise
39-44	CAPACY	total plant capacity (Mw)
45-52	OUTPUT	total plant output ($kwhrx10^6$)
53-57	UTIL	plant utilization rate (percent)
58-65	BTUI	total Btu input from all fuel for initial year in $Btux10^{13}$
66-70	SULPH	sulfur percent of coal used in initial study year
71-73	COAL	percent of Btu input from coal
74-76	OIL	percent of Btu input from oil
77-79	GAS	percent of Btu input from gas
80	ADD	number of boiler cards following this plant card

Card type 2 - (Boiler Card) - (20X, I3, 9X, I2, I2, 2X, F6.1, 8X, F5.1, 13X, 3A3, I1)

Col.		
13-23	BCODE	FPC code with last two digits changed to identify boiler
33-36	DATE	month and year in which boiler was built or retired
39-44	BCAP	boiler capacity (Mw); a negative capacity is used to indicate retirement
53-57	BUTIL	boiler utilization rate (percent)
72	DCOAL	X if boiler is designed for coal use
75	DOIL	X if boiler is designed for oil use
78	DGAS	X if boiler is designed for natural gas use
80	WET	1 = wet bottom boiler 0 = dry bottom boiler

After all plant and boiler data a blank card is needed

Card type 3 (additional plant data)
(12X, A4, I2, 1X, I4, 1X, 2F6.0, I6, F6.3, F8.0)

13-23	CODE	FPC code number
25-30	HSCOST	current cost of coal, termed 'high sulfur coal' in ¢/Btux10^6
31-36	BTULB	Btu content of coal Btu/lb
37-42	MILES	miles from plant to low sulfur coal mines
43-48	ECRAT	concentration - emission ratio $\left(\frac{\mu g/m^3}{ton/day}\right)$
49-56	FLGRT	flue gas rate (scfm)

I.C SAMPLE PROBLEM

The sample problem corresponds to run number 10 in Appendix V. The following input specifications are used:

1. Plants are grouped only by age.
2. All 3 types of LSC are used; the supply of types 1 and 3 grows with demand and the supply of type 2 is given year by year.
3. Scrubber supply grows with demand.
4. Strategies are specified by state according to the State Implementation Plan (SIP). New plants are under New Source Performance Standards (NSPS). A standard of 1.21 is used in Ohio because the 1.0 SIP standard is not attainable with the LSC used (8300 Btu/lb, .5% sulfur).

   a. Input Listing for Sample Problem

   The input cards for the regular card input, FT05F001, are listed here. The first 6 cards, of which 4 are blank, are the Group Data as defined in the previous section (I.2). The next 7 cards are the LSC Cost and Supply Data. The Scrubber Supply Data takes only one card and the remainder of the cards (16) constitute the Strategy Data.

```
//GO.SYSIN DD *

    2        1                  2
  73.9

2.31   4.4   .0065   3.     8300. .5
    3   25.0      75   12.2
3.47   4.4   .0065   3.     8300. .5
    1             75   1.0
 2.0   4.0    6.0    8.0   10.0   12.0   14.0
8.59   3.9   .0065   3.    12200. .6
    3   50.0      77   6.0
    3  215.0      75  880.     4.       1
  15
  75   1.21       1                                  50.    5000.   74.    82.
  75   2.4        1                                  00.    50.     74.    82.
  75  290.0       3      13                          50.    5000.   00.    74.
  75   1.8        1      13       3                  50.    5000.   00.    74.
 065    067     070
  75   6.0        1      13                          00.    50.     00.    74.
  75   0.0        4      14                                         00.    74.
  75  290.0       3      49                          50.    5000.   00.    74.
  75   6.0        1      49                          00.    50.     00.    74.
  75   3.2        1      22                          00.    50.     00.    74.
  75  290.0       3      22                          50.    5000.   00.    70.
  75   2.4        1      22                          50.    5000.   70.    74.
  75   4.0        1      35                          00.    25.     00.    74.
  75  1.21        1      35                          25.    5000.   00.    74.
  78   2.4        1      22                          00.    50.     00.    74.
  78   1.6        1      22                          50.    5000.   70.    74.
```

b. Plant Data Base Input

A sample of the plant data is shown in Table I.1. The entire data base consists of nearly 200 plants and is usually read in from tape or disk on Unit 8 (FT08F001). It can be entered on cards if the regular input is ended with a /* card, followed by a //FT08F001 DD * card and then by the plant data. Any plants in the data base that do not use enough coal (2%) or are retired completely in the first half of the study period are eliminated by the program.

c. Output for Sample Problem (see pp I.14-I.23)

The group and priority definitions and the strategy input are printed, with some annotation, in the first section of the output.

After the plants have been analyzed for missing data and for inclusion in the study, projections are made for the duration of the study period. The total capacity and Btu input of coal needed are printed for each year (1971-1982).

The next section lists all plants that come under a type 3 emission standard ($\mu g/m^3$) after their standard has been converted to lb_2SO /Btux10^6. These are listed in the year that the standard first applies so they may be interspersed with the next section.

As the simulation is done year by year, the supply and demand parameters are printed. The supply of LSC is given in one line with the 3 numbers referring to type 1, type 2, and type 3, respectively.

After the simulation is accomplished, the results are summarized in several tables. Parts of these tables have been removed in this listing.

d. Optional Output (see pp I.24-I.26)

During the year-by-year simulation, the assignment and costs for each plant can be printed. The plants are listed in the order they are encountered according to the priority scheme. This order may change from year to year since the air quality standards and the priority are reassigned each year. Costs are calculated and printed for both LSC and scrubbers unless a scrubber has previously been assigned or unless a plant is in compliance without using LSC or scrubbers.

This output is quite long and only a sample of it is listed here. The annotation provided should be sufficient to explain what is being printed. Because of the length of this output, it is printed on a separate unit from the regular output. It can be obtained by including a control card: //FT09F001 DD SYSOUT=A. If this output is not needed, a card of the form //FT09F001 DD DUMMY must be included in the job control language (JCL) statements.

Table I.1. Sample Plant Data Base Input

NAME	CODE	LOCATION		CAP.	OUTPUT		BTUIN	SULF	FUEL MIX			
CARDINAL	071000-0100	35U181JEF	1	21230.5	6207.0		5.6876	2.94	99	1		2
	071000-0101		67	1230.5		59.6			X			0
	071000-0110		1076	615.0					X			
CLEV LAKE RD	071000-0200	35U174CUY	1	160.0	394.4		0.5733		98	2		
COLUMBUS	071000-0300	35U176FRA	1	44.5	126.1		0.2578		32	2		661
	071000-0300		0174	-19.5					X		X	
DOVER	071000-0400	35R183TUS	1	235.9	72.5		0.1218		100			
E. PALESTINE	071000-0500	35R181COL	1	216.5	27.2		0.0756		100			
CELINA	071000-0600	35R177MER	1	25.0	37.7		0.0656		100			2
	071000-0600		0672	-12.5								
	071000-0610		0180	20.0								
NAPOLEON	071000-0700	35R177HEN	1	23.5	57.4		0.0975		100			
NORWALK	071000-0800	35R130HUR	1	31.3	64.0		0.1141		99	1		
VINE ST	071000-0900	35R175WAY	1	44.5	113.4		0.1891		96			43
	071000-0910		0672	19.5					X			
	071000-0920		0677	25.0					X			
	071000-0930		0682	44.0								
PAINESVILLE	071000-1100	35U174LAK	1	38.0	111.4		0.1980		100			1
	071000-1110		0774	25.0					X			
READING	071000-1200	35U079HAM	1	15.3	43.2		0.0845		100			
ST MARYS	071000-1300	35R177AUG	1	22.6	29.8		0.0537		98	2		
SHELBY	071000-1400	35U175RIC	1	27.5	62.3		0.1008		100			1
	071000-1410		0672	12.5					X			
BCKYE PWR	071000-1500	35	1081	600.0								
COFFEEN	078500-0100	13R075MON	1	3388.9	1811.9		1.8780	4.48	100			2
	078500-0101		65	388.9		60.4			X			1
	078500-0110		0672	616.6					X			
GRAND TOWER	078500-0200	13R074JAC	1	1232.6	1036.3		1.1032	2.38	100			4
	078500-0201		24	50.0		1.28			X			0
	078500-0202		50	69.0		60.3			X			0
	078500-0203		58	113.6		85.7			X			0
	078500-0201		0672	-50.0					X			
HUTSONVILLE	078500-0300	13R074CRA	1	1212.5	884.8		0.9707	2.30	100			2
	078500-0301		41	62.5		23.1			X			0
	078500-0302		54	150.0		66.1			X			0
MEREDOSIA	078500-0400	13R075MOR	1	1354.4	1738.3		1.7515	3.54	100			3
	078500-0401		49	115.0		36.9			X			0
	078500-0402		60	239.4		82.7			X			0
	078500-0420		0475	200.0						X		
NEWTON	078500-0500	13R074JAS	0377	600.0					100			2
	078500-0510		0480	600.0					X			
	078500-0520		0482	600.0					X			
EDWARDS	079000-0100	13U065PEO	1	2386.0	2352.7		2.2460	2.83	99	1		3
	079000-0101		60	126.2		71.0			X			1
	079000-0102		68	259.8		76.0			X			1
	079000-0110		0672	350.0					X			
KEYSTONE	079000-0200	13U065PEO	1	254.4	118.4		0.1152	2.86	34			663
	079000-0201		47	15.6		17.4			X			0
	079000-0202		56	31.3		32.9					X	0
	079000-0203		67	7.5		51.5					X	0
WALLACE	079000-0400	13U065TAZ	1	1349.3	1388.3		1.6743	3.04	71			296
	079000-0401		25	44.4		01.2					X	0
	079000-0402		40	65.2		39.6			X		X	0
	079000-0403		49	40.2		32.9			X			0
	079000-0404		52	85.9		54.3			X			0
	079000-0405		58	113.6		60.2			X			0
	079000-0400		0672	-26.4					X			
DUCK CR	079000-0500	13R065FUL	0176	2400.0					100			1
	079000-0510		0680	400.0					X			
ASHTABULA	104000-0100	35R178ASH	1	456.0	1898.6		2.0954	3.27	100			3
	104000-0101		31	200.0		19.4			X			0

c. OUTPUT FOR SAMPLE PROBLEM (I.C)

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PLANTS ARE GROUPED BY  AGE      WITH    2 GROUPS, HAVING PRIORITIES       1      2
AND HAVING  AGE      LIMITS          73.90

 # YEAR    STANDARD TYPE STATE AQCR COUNTY U/R  CAPACITY MW    YEAR BUILT
 1  75   0.1210E 01  1      0    0                50. 5000.   74.   82.
 2  75   0.2400E 01  1      0    0                 0.   50.   74.   82.
 3  75   0.2900E 03  3     13    0                50. 5000.    0.   74.
 4  75   0.1800E 01  1     13    3                50. 5000.    0.   74.
AQCR LIST    065    067    070
 5  75   0.6000E 01  1     13    0                 0.   50.    0.   74.
 6  75   0.0         4     14    0                 0.    0.    0.   74.
 7  75   0.2900E 03  3     49    0                50. 5000.    0.   74.
 8  75   0.6000E 01  1     49    0                 0.   50.    0.   74.
 9  75   0.3200E 01  1     22    0                 0.   50.    0.   74.
10  75   0.2900E 03  3     22    0                50. 5000.    0.   70.
11  75   0.2400E 01  1     22    0                50. 5000.   70.   74.
12  75   0.4000E 01  1     35    0                 0.   25.    0.   74.
13  75   0.1210E 01  1     35    0                25. 5000.    0.   74.
14  78   0.2400E 01  1     22    0                 0.   50.    0.   74.
15  78   0.1600E 01  1     22    0                50. 5000.   70.   74.
NUMBER OF PLANTS IN SYSTEM IN FIRST YEAR 180
TOTAL COAL FIRED CAPACITY    ( MW)
          56403.81           59014.05           63432.90           66090.06           69481.69           73235.81
          76773.25           79562.94           83386.38           87335.56           92244.38           96310.94
TOTAL COAL DEMAND  ( 10 TO 13 BTU)
             277.06             293.89             321.70             339.32             360.35             383.65
             405.06             421.73             444.97             468.85             497.97             522.10
  COFFEEN       AQ STANDARD        3.1421 CONC/EMISS RATIO     0.820
  GRAND TOWER   AQ STANDARD        0.9448 CONC/EMISS RATIO    14.621
  HUTSONVILLE   AQ STANDARD        3.9567 CONC/EMISS RATIO     2.911
  MEREDOSIA     AQ STANDARD        3.5155 CONC/EMISS RATIO     2.139
  EDWARDS       AQ STANDARD        6.4774 CONC/EMISS RATIO     0.590
  WALLACE       AQ STANDARD        6.9278 CONC/EMISS RATIO     1.154
  FISK          AQ STANDARD        4.2482 CONC/EMISS RATIO     1.097
  CRAWFORD      AQ STANDARD        3.6891 CONC/EMISS RATIO     1.163
  DIXON         AQ STANDARD        9.2504 CONC/EMISS RATIO     2.091
  JOLIET        AQ STANDARD        3.2535 CONC/EMISS RATIO     0.431
  KINCAID       AQ STANDARD        4.5189 CONC/EMISS RATIO     0.428
  POWERTON      AQ STANDARD        9.8303 CONC/EMISS RATIO     0.176
  SABROOKE      AQ STANDARD        9.0095 CONC/EMISS RATIO     1.737
  WAUKEGAN      AQ STANDARD        5.9371 CONC/EMISS RATIO     0.463
  WILL CO.      AQ STANDARD        4.7648 CONC/EMISS RATIO     0.457
  JOPPA         AQ STANDARD        3.7824 CONC/EMISS RATIO     0.639
  MARION        AQ STANDARD        6.2203 CONC/EMISS RATIO     3.500
  HAVANA        AQ STANDARD        6.5888 CONC/EMISS RATIO     1.403
  HENNEPIN      AQ STANDARD       14.0814 CONC/EMISS RATIO     0.616
  VERMILION     AQ STANDARD       15.2569 CONC/EMISS RATIO     0.896
  WOOD RIVER    AQ STANDARD        6.6653 CONC/EMISS RATIO     0.611
  BALDWIN #1    AQ STANDARD        4.1219 CONC/EMISS RATIO     0.424
  DALLMAN       AQ STANDARD        8.2649 CONC/EMISS RATIO     1.863
  LAKESIDE      AQ STANDARD        1.7384 CONC/EMISS RATIO    11.611
  CAHOKIA       AQ STANDARD        3.4824 CONC/EMISS RATIO     2.997
  VENICE #2     AQ STANDARD        2.5026 CONC/EMISS RATIO     1.674
  U OF ILL      AQ STANDARD       11.7171 CONC/EMISS RATIO     2.172
  ALMA          AQ STANDARD       24.9759 CONC/EMISS RATIO     0.548
  GENOA #3      AQ STANDARD       12.9213 CONC/EMISS RATIO     0.683
  STONEMAN      AQ STANDARD        8.6677 CONC/EMISS RATIO     5.010
  BLOUNT ST.    AQ STANDARD        6.4194 CONC/EMISS RATIO     2.048
  BAY FRONT     AQ STANDARD        8.6077 CONC/EMISS RATIO     3.500
  MANITOWOC     AQ STANDARD        7.1152 CONC/EMISS RATIO     3.500
  N. OAK CREEK  AQ STANDARD        4.5470 CONC/EMISS RATIO     1.147
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PT. WASH	AQ STANDARD	13.0819	CONC/EMISS RATIO	0.441
S. OAK CREEK	AQ STANDARD	5.3116	CONC/EMISS RATIO	0.448
VALLEY	AQ STANDARD	6.4150	CONC/EMISS RATIO	1.096
EDGEWATER	AQ STANDARD	6.6690	CONC/EMISS RATIO	0.863
DEWEY	AQ STANDARD	15.8909	CONC/EMISS RATIO	0.767
ROCK R.	AQ STANDARD	8.9451	CONC/EMISS RATIO	1.907
PULLIAM	AQ STANDARD	3.2306	CONC/EMISS RATIO	1.911
WESTON	AQ STANDARD	14.6286	CONC/EMISS RATIO	1.242
COBB	AQ STANDARD	5.8879	CONC/EMISS RATIO	1.270
KARN	AQ STANDARD	16.9489	CONC/EMISS RATIO	0.329
CAMPBELL	AQ STANDARD	11.1899	CONC/EMISS RATIO	0.408
WEADDOCH	AQ STANDARD	3.5489	CONC/EMISS RATIO	1.115
WHITING	AQ STANDARD	6.1387	CONC/EMISS RATIO	1.355
MISTERSKY	AQ STANDARD	1.5369	CONC/EMISS RATIO	7.809
DE YOUNG	AQ STANDARD	7.8728	CONC/EMISS RATIO	3.500
ECKERT	AQ STANDARD	2.6841	CONC/EMISS RATIO	2.042
OTTAWA	AQ STANDARD	12.6469	CONC/EMISS RATIO	1.727
CONNER CR	AQ STANDARD	2.9721	CONC/EMISS RATIO	1.495
HARBOR BEACH	AQ STANDARD	13.3889	CONC/EMISS RATIO	1.578
MARYSVILLE	AQ STANDARD	2.6584	CONC/EMISS RATIO	3.231
R ROUGE	AQ STANDARD	1.7813	CONC/EMISS RATIO	1.306
ST. CLAIR	AQ STANDARD	2.5071	CONC/EMISS RATIO	0.610
TRENTON CH	AQ STANDARD	4.9172	CONC/EMISS RATIO	0.646
MONROE	AQ STANDARD	4.0561	CONC/EMISS RATIO	0.177
PRESQUE ISLE	AQ STANDARD	3.0174	CONC/EMISS RATIO	2.394

YEAR 1975
SUPPLY LSC MTONS BY TYPE 0.1220E 02 0.1000E 01 0.0 TOTAL 0.1320E 02 SUPPLY FGD MW 0.8800E 03

TOTAL EXCESS DEMAND FOR LSC IN M-TONS 132.71
EXCESS DEMAND AT LEAST COST 98.35
TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW 37799.68
EXCESS DEMAND AT LEAST COST 8371.52

TOTAL OF 13.200 MTONS OF LOW SULFUR COAL USED
EXCESS SUPPLY WAS 0.000 MTONS
TOTAL OF 870.75 MW OF SCRUBBERS CURRENTLY INSTALLED
EXCESS SUPPLY WAS 9.25 MW

YEAR 1976
SUPPLY LSC MTONS BY TYPE 0.1525E 02 0.2000E 01 0.0 TOTAL 0.1725E 02 SUPPLY FGD MW 0.2743E 04

TOTAL EXCESS DEMAND FOR LSC IN M-TONS 133.09
EXCESS DEMAND AT LEAST COST 121.41
TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW 37817.29
EXCESS DEMAND AT LEAST COST 2406.75

TOTAL OF 17.250 MTONS OF LOW SULFUR COAL USED
EXCESS SUPPLY WAS 0.000 MTONS
TOTAL OF 2738.31 MW OF SCRUBBERS CURRENTLY INSTALLED
EXCESS SUPPLY WAS 4.57 MW

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    YEAR   1977
SUPPLY LSC MTONS BY TYPE  0.1906E 02  0.4000E 01  0.6000E 01 TOTAL  0.2906E 02 SUPPLY FGD MW  0.6754E 04

 TOTAL EXCESS DEMAND FOR LSC IN M-TONS        118.93
 EXCESS DEMAND AT LEAST COST         118.93
 TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW      33854.52
 EXCESS DEMAND AT LEAST COST           0.0

 TOTAL OF      29.062 MTONS OF LOW SULFUR COAL USED
 EXCESS SUPPLY WAS        0.001 MTONS
 TOTAL OF    6707.80 MW OF SCRUBBERS CURRENTLY INSTALLED
 EXCESS SUPPLY WAS       45.75 MW


    YEAR   1978
SUPPLY LSC MTONS BY TYPE  0.2383E 02  0.6000E 01  0.8999E 01 TOTAL  0.3883E 02 SUPPLY FGD MW  0.1524E 05

 TOTAL EXCESS DEMAND FOR LSC IN M-TONS         86.84
 EXCESS DEMAND AT LEAST COST          86.84
 TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW      25496.07
 EXCESS DEMAND AT LEAST COST           0.0

 TOTAL OF      38.827 MTONS OF LOW SULFUR COAL USED
 EXCESS SUPPLY WAS        0.000 MTONS
 TOTAL OF   15220.15 MW OF SCRUBBERS CURRENTLY INSTALLED
 EXCESS SUPPLY WAS       22.04 MW


    YEAR   1979
SUPPLY LSC MTONS BY TYPE  0.2979E 02  0.8000E 01  0.1350E 02 TOTAL  0.5128E 02 SUPPLY FGD MW  0.3352E 05

 TOTAL EXCESS DEMAND FOR LSC IN M-TONS         71.21
 EXCESS DEMAND AT LEAST COST          71.21
 TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW      21450.99
 EXCESS DEMAND AT LEAST COST           0.0

 TOTAL OF      51.283 MTONS OF LOW SULFUR COAL USED
 EXCESS SUPPLY WAS        0.000 MTONS
 TOTAL OF   18731.86 MW OF SCRUBBERS CURRENTLY INSTALLED
 EXCESS SUPPLY WAS   14789.85 MW


    YEAR   1980
SUPPLY LSC MTONS BY TYPE  0.3723E 02  0.1000E 02  0.2025E 02 TOTAL  0.6748E 02 SUPPLY FGD MW  0.3352E 05

 TOTAL EXCESS DEMAND FOR LSC IN M-TONS         67.84
 EXCESS DEMAND AT LEAST COST          67.84
 TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW      20516.23
 EXCESS DEMAND AT LEAST COST           0.0

 TOTAL OF      67.478 MTONS OF LOW SULFUR COAL USED
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EXCESS SUPPLY WAS 0.000 MTONS
TOTAL OF 19712.31 MW OF SCRUBBERS CURRENTLY INSTALLED
EXCESS SUPPLY WAS 13809.40 MW

YEAR 1981
SUPPLY LSC MTONS BY TYPE 0.4654E 02 0.1200E 02 0.3037E 02 TOTAL 0.8891E 02 SUPPLY FGD MW 0.3352E 05

TOTAL EXCESS DEMAND FOR LSC IN M-TONS 60.76
EXCESS DEMAND AT LEAST COST 60.76
TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW 18454.20
EXCESS DEMAND AT LEAST COST 0.0

TOTAL OF 88.908 MTONS OF LOW SULFUR COAL USED
EXCESS SUPPLY WAS 0.000 MTONS
TOTAL OF 19712.31 MW OF SCRUBBERS CURRENTLY INSTALLED
EXCESS SUPPLY WAS 13809.40 MW

YEAR 1982
SUPPLY LSC MTONS BY TYPE 0.5817E 02 0.1400E 02 0.4555E 02 TOTAL 0.1177E 03 SUPPLY FGD MW 0.3352E 05

TOTAL EXCESS DEMAND FOR LSC IN M-TONS 36.11
EXCESS DEMAND AT LEAST COST 36.11
TOTAL EXCESS DEMAND FOR SCRUBBERS IN MW 11394.41
EXCESS DEMAND AT LEAST COST 0.0

TOTAL OF 117.727 MTONS OF LOW SULFUR COAL USED
EXCESS SUPPLY WAS 0.000 MTONS
TOTAL OF 19736.50 MW OF SCRUBBERS CURRENTLY INSTALLED
EXCESS SUPPLY WAS 13785.21 MW

RESPONSE AND ANUAL DOLLAR COST OF PLANTS
0 -- PLANT DOES NOT EXIST
1 -- BURNS HIGH SULFUR COAL
2 -- BURNS LOW SULFUR COAL
3 -- INSTALLS SCRUBBER
4 -- COMPLIANCE NO POSSIBLE WITH PRESENT STANDARDS

PLANT NAME	1975	1976	1977	1978	1979	1980	1981	1982
CARDINAL	1 0.	1 0.	1 0.	3 42046912.	3 43728784.	3 45477888.	3 47296976.	3 49188816.
CLEV LAKE RD	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
COLUMBUS	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
DOVER	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
E. PALESTINE	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
CELINA	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
NAPOLEON	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
NORWALK	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
VINE ST	1 0.	3 2222037.	3 2800400.	3 3278891.	3 3410046.	3 3546445.	3 3688299.	3 4560381.
PAINESVILLE	1 0.	1 0.	1 0.	1 0.	3 2475180.	3 2574185.	3 2677150.	3 2784235.
READING	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
ST MARYS	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
SHELBY	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
BCKYE PWR	0 0.	0 0.	0 0.	0 0.	0 0.	0 0.	2 3278663.	2 9897248.
COFFEEN	2 14432640.	1 0.	1 0.	1 0.	2 14450416.	1 0.	2 15069408.	2 15389664.
GRAND TOWER	4 0.	4 0.	4 0.	4 0.	4 0.	4 0.	4 0.	4 0.
HUTSONVILLE	3 695994.	3 723834.	3 752787.	3 782898.	3 814213.	3 846781.	3 880652.	3 915877.

WINNETKA	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
FAIRFIELD	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
HIGHLAND	2 24584.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	2 28676.
MT CARMEL	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
PERU	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
ROCHELLE	1 0.	1 0.	1 0.	2 14114.	1 0.	1 0.	1 0.	1 0.
E WELLS ST	1 0.	2 3336.	2 3350.	1 0.	1 0.	1 0.	2 3380.	1 0.
N. OAK CREEK	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
PT. WASH	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
S. OAK CREEK	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
VALLEY	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
WEP ILR	0 0.	0 0.	0 0.	0 0.	2 2877317.	2 6559424.	2 12331584.	2 8699952.
EDGEWATER	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
DEWEY	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
ROCK R.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.
COLUMBIA	2 1689866.	2 3587808.	2 3607808.	2 4357744.	2 5810208.	2 7228080.	2 7985360.	2 8057344.
PULLIAM	1 0.	3 3300691.	3 3432716.	3 3570022.	3 3712821.	3 3861332.	3 4015782.	3 4176411.
WESTON	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.	1 0.

TOTAL COST (IN DOLLARS) OF LOW SULFUR COAL AND SCRUBBERS FOR ALL PLANTS IN THE REGION

92650720. 155773904. 340491520. 615900928. 796039168. 915244288. 1066079488. 1242459392.

RESPONSE AND COST IN MILS/KWHR FOR PLANTS
0 -- PLANT DOES NOT EXIST
1 -- BURNS HIGH SULFUR COAL
2 -- BURNS LOW SULFUR COAL
3 -- INSTALLS SCRUBBER
4 -- COMPLIANCE NO POSSIBLE WITH PRESENT STANDARDS

PLANT NAME	1975	1976	1977	1978	1979	1980	1981	1982
CARDINAL	1 0.0	1 0.0	1 0.0	3 4.108	3 4.272	3 4.443	3 4.620	3 4.805
CLEV LAKE RD	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
COLUMBUS	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
DOVER	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
E. PALESTINE	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
CELINA	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
NAPOLEON	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
NORWALK	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
VINE ST	1 0.0	3 9.944	3 9.711	3 9.795	3 10.187	3 10.595	3 11.018	3 10.157
PAINESVILLE	1 0.0	1 0.0	1 0.0	1 0.0	3 12.721	3 13.230	3 13.759	3 14.310
READING	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
ST MARYS	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
SHELBY	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
BCKYE PWR	0 0.0	0 0.0	0 0.0	0 0.0	0 0.0	0 0.0	2 3.327	2 2.511
COFFEEN	2 2.708	1 0.0	1 0.0	1 0.0	2 2.711	1 0.0	2 2.828	2 2.888
GRAND TOWER	4 0.0	4 0.0	4 0.0	4 0.0	4 0.0	4 0.0	4 0.0	4 0.0
HUTSONVILLE	3 0.787	3 0.818	3 0.851	3 0.885	3 0.920	3 0.957	3 0.995	3 1.035

WINNETKA	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
FAIRFIELD	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
HIGHLAND	2 1.036	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	2 1.209
MT CARMEL	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
PERU	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
ROCHELLE	1 0.0	1 0.0	1 0.0	2 0.348	1 0.0	1 0.0	1 0.0	1 0.0
E WELLS ST	1 0.0	2 0.119	2 0.120	1 0.0	1 0.0	1 0.0	2 0.121	1 0.0
N. OAK CREEK	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
PT. WASH	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
S. OAK CREEK	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
VALLEY	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
WEP ILR	0 0.0	0 0.0	0 0.0	0 0.0	2 1.294	2 1.087	2 1.618	2 1.142
EDGEWATER	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
DEWEY	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
ROCK R.	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0
COLUMBIA	2 0.586	2 1.036	2 1.042	2 0.795	2 0.839	2 1.044	2 1.153	2 1.164
PULLIAM	1 0.0	3 1.589	3 1.653	3 1.719	3 1.788	3 1.859	3 1.933	3 2.011
WESTON	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0	1 0.0

AVERAGE COST (IN MILS/KWHR) OF LOW SULFUR COAL AND SCRUBBERS FOR ALL PLANTS IN THE REGION

2.889	2.960	3.129	3.037	3.054	3.053	3.070	2.965

PLANTS WHICH ARE NOT IN COMPLIANCE WITH AIR QUALITY STANDARDS
WITH YEARS OF NON-COMPLIANCE INDICATED

PLANT NAME	1975	1976	1977	1978	1979	1980	1981	1982
CARDINAL	X	X	X					
CLEV LAKE RD	X	X	X	X	X	X	X	X
COLUMBUS	X	X	X	X	X	X	X	X
DOVER	X	X	X	X	X	X	X	X
E. PALESTINE	X	X	X	X	X	X	X	X
CELINA	X	X	X	X	X	X	X	X
NAPOLEON	X	X	X	X	X	X	X	X
NORWALK	X	X	X	X	X	X	X	X
VINE ST	X							
PAINESVILLE	X	X	X	X				
READING	X	X	X	X	X	X	X	X
ST MARYS	X	X	X	X	X	X	X	X
SHELBY	X	X	X	X	X	X	X	X
COFFEEN		X	X	X		X		
GRAND TOWER	X	X	X	X	X	X	X	X
MEREDOSIA	X	X	X	X	X	X	X	X
EDWARDS	X	X	X	X	X	X	X	X
WALLACE	X	X	X	X	X	X	X	X
ASHTABULA	X	X	X	X	X	X	X	X
AVON	X	X	X	X	X	X	X	
EAST LAKE	X	X	X	X	X	X	X	
LAKESHORE	X	X	X	X	X	X	X	X
CONESVILLE	X	X	X					
PICWAY	X	X	X	X	X	X	X	X
POSTON	X	X	X	X				
STATE LINE	X	X	X	X	X	X	X	X
FISK	X	X	X	X				
CRAWFORD	X	X	X	X	X	X	X	X
JOLIET	X	X	X	X	X	X	X	
KINCAID	X	X						
POWERTON	X	X	X	X	X			
WAUKEGAN	X	X	X	X	X	X	X	X
WILL CO.	X	X	X	X	X	X	X	
MISTERSKY	X	X	X	X	X	X	X	X
COLDWATER	X	X	X	X		X	X	X
GLADSTONE	X	X	X	X	X	X	X	X
HARBOR IS	X	X	X	X	X	X	X	X
SHIRAS	X	X	X	X	X	X	X	X
BAYSIDE	X	X	X	X	X	X	X	X
ADVANCE	X	X	X	X		X	X	X
JOPPA	X	X	X	X				
MARION	X	X	X		X		X	X
PEARL		X	X	X	X	X		X
RATTS	X	X	X	X				
CRAWFORDSVLE	X	X	X	X	X	X	X	X
FT WAYNE		X	X	X	X	X	X	X
FRANKFORD	X	X	X	X	X	X	X	X
JASPER	X	X	X	X	X	X	X	X
LOGANSPORT	X	X	X	X	X	X	X	X
PERU	X	X	X	X	X	X	X	X
RICHMOND	X	X	X	X	X	X	X	X
WASHINGTON	X		X	X	X	X	X	X
HAVANA	X	X		X	X	X	X	X
WOOD RIVER	X	X	X	X				
BALDWIN #1	X							
CLIFTY CR.	X	X						
BREED	X	X	X	X	X	X	X	X

TANNERS CR	X	X	X					
TWIN BRANCH	X	X	X	X	X	X	X	X
STOUT	X	X	X	X	X	X	X	X
PRITCHARD	X	X	X	X	X	X	X	X
PERRY	X	X	X	X	X	X	X	X
PETERSBURG	X	X	X					
ECKERT	X	X	X	X				
RICHLAND	X			X	X	X		X
BAILLY	X	X	X	X	X	X	X	X
MITCHELL	X	X	X	X	X	X	X	X
MICH CITY	X	X	X	X	X	X	X	X
SCHAHFER		X						
EDGEWATER	X	X	X	X	X	X	X	X
GORGE	X	X	X	X	X	X	X	X
MAD RIVER	X	X	X	X	X	X	X	X
NILES	X	X	X	X				
BURGER	X	X	X	X	X	X	X	X
SAMMIS	X	X						
MUSKINGUM	X	X		X	X			
PHILO	X	X	X	X	X	X	X	
TIDD	X	X	X	X				
KYGER CR	X	X	X					
PIQUA	X	X	X	X	X	X	X	X
DRESSER	X		X		X	X	X	X
EDWARDSPORT	X	X	X	X	X	X	X	X
NOBLESVILLE	X	X	X	X	X	X	X	X
GALLAGHER	X	X						
WABASH RIVER	X	X	X					
CAYUGA	X	X	X	X				
CULLEY		X	X	X	X	X		X
LAKESIDE	X	X	X	X	X	X	X	X
MIAMI FT	X	X	X	X	X	X		
BECKJORD	X	X	X	X	X	X	X	
TAIT	X	X	X	X				
HUTCHINGS	X	X	X	X				
STUART	X	X	X					
CONNER CR	X	X						
MARYSVILLE	X	X	X	X	X	X	X	X
R ROUGE	X	X	X	X	X	X	X	X
ST. CLAIR	X	X	X	X	X	X	X	
MONROE	X	X	X					
ACME	X	X	X	X	X	X	X	X
BAY SHORE	X	X	X	X	X	X	X	X
CAHOKIA	X	X	X	X	X	X	X	X
VENICE #2	X	X	X	X	X	X	X	X
ESCANABA	X	X	X	X	X	X	X	

TOTAL CAPACITY (IN MEGAWATTS) OF ALL PLANTS IN THE REGION
WHICH ARE IN COMPLIANCE WITH AIR QUALITY STANDARDS

14783.07	17932.11	27693.93	44643.00	55111.71	61589.92	69114.56	81633.88

TOTAL CAPACITY (IN MEGAWATTS) OF ALL PLANTS IN THE REGION
WHICH ARE NOT IN COMPLIANCE WITH AIR QUALITY STANDARDS

54698.62	55303.71	49079.32	34919.94	28274.66	25745.64	23129.81	14677.06

d. OPTIONAL OUTPUT (I.C)

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WARRICK                    4520   0 500
SCRUBBER(  1) CAP COST PER KW   45.2797    ANNUAL COST PER KW    18.9914
   S HANDLING0.806786E 01 O&M0.299965E 01 CAP CHG0.792394E 01 $ PER KW
ANNUAL CAPACITY FACTOR      0.793    SYSTEM PENALTY        1.24 MILS KWHR
ANNUAL FGD COST          0.238129E 08    MILS KWHR    4.6843    DOLLARS PER KW   32.5313  SIZE MW    696.918
ANNUAL FGD + HSC COST  0.423487E 08    MILS KWHR    8.3305
***** WARRICK       ***** ) IS ASSIGNED A SCRUBBER OF  696.918 MW IN YEAR   76


TORONTO                    3545   0 600
SCRUBBER(  1) CAP COST PER KW   65.2314    ANNUAL COST PER KW    27.4637
   S HANDLING0.374154E 01 O&M0.350047E 01 CAP CHG0.202217E 02 $ PER KW
ANNUAL CAPACITY FACTOR      0.454    SYSTEM PENALTY        1.85 MILS KWHR
ANNUAL FGD COST          0.653375E 07    MILS KWHR    9.3473    DOLLARS PER KW   37.1658  SIZE MW    148.837
ANNUAL FGD + HSC COST  0.110279E 08    MILS KWHR   15.7767
***** TORONTO       ***** ) IS ASSIGNED A SCRUBBER OF  148.837 MW IN YEAR   76


HUTSONVILLE                0785   0 300
SCRUBBER(  1) CAP COST PER KW   58.3334    ANNUAL COST PER KW    15.7571
   S HANDLING0.241043E 01 O&M0.313833E 01 CAP CHG0.102083E 02 $ PER KW
ANNUAL CAPACITY FACTOR      0.475    SYSTEM PENALTY        1.85 MILS KWHR
ANNUAL FGD COST          0.723834E 06    MILS KWHR    0.8181    DOLLARS PER KW    3.4063  SIZE MW     25.000
ANNUAL FGD + HSC COST  0.628559E 07    MILS KWHR    7.1040
***** HUTSONVILLE   ***** ) IS ASSIGNED A SCRUBBER OF   25.000 MW IN YEAR   76


GAVIN                      3550   0 700
CURRENT HSC CENTS MBTU      0.5758E 02    DEMAND LSC MTONS      0.9252E 01      0.9252E 01      0.6036E 01
LSC FUEL                CENTS MBTU   80.5598    MILS KWHR    7.2504
ANNUAL CAPACITY FACTOR      0.750 SYSTEM PENALTY       0.39  MILS KWHR
LSC + HSC FUEL    CENTS MBTU   80.5367    MILS KWHR    7.2483    ANNUAL DOLLARS  0.123815E 09
CONVERSION COST    0.0              ANNUALIZED    0.0
ANNUAL TOTAL COST        0.130460E 09    MILS KWHR    7.6373
SCRUBBER(  1) CAP COST PER KW   31.3316    ANNUAL COST PER KW    13.2845
   S HANDLING0.595258E 01 O&M0.184894E 01 CAP CHG0.548302E 01 $ PER KW
ANNUAL CAPACITY FACTOR      0.750    SYSTEM PENALTY        1.24 MILS KWHR
ANNUAL FGD COST          0.648966E 08    MILS KWHR    3.7991    DOLLARS PER KW   24.9602  SIZE MW   2477.208
ANNUAL FGD + HSC COST  0.153425E 09    MILS KWHR    8.9817
***** GAVIN       *****  IS ASSIGNED TO BURN   9.252 M-TONS OF TYPE  1 LOW SULFUR COAL IN YEAR  76


GIBSON                     4045   01100
CURRENT HSC CENTS MBTU      0.5758E 02    DEMAND LSC MTONS      0.4048E 01      0.4048E 01      0.2641E 01
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LSC FUEL               CENTS MBTU   73.2227    MILS KWHR    6.5900
ANNUAL CAPACITY FACTOR     0.750 SYSTEM PENALTY       0.39  MILS KWHR
LSC + HSC FUEL    CENTS MBTU   73.2069    MILS KWHR    6.5886    ANNUAL DOLLARS  0.492392E 08
CONVERSION COST    0.0            ANNUALIZED    0.0
ANNUAL TOTAL COST       0.521462E 08    MILS KWHR    6.9776
SCRUBBER(  1) CAP COST PER KW   37.0464    ANNUAL COST PER KW   14.0351
   S HANDLING0.527035E 01 O&M0.228166E 01 CAP CHG0.648312E 01 $ PER KW
ANNUAL CAPACITY FACTOR     0.750    SYSTEM PENALTY       1.24 MILS KWHR
ANNUAL FGD COST         0.294569E 08    MILS KWHR    3.9416    DOLLARS PER KW   25.8961  SIZE MW   1083.779
ANNUAL FGD + HSC COST  0.681882E 08    MILS KWHR    9.1242
***** GIBSON      *****  IS ASSIGNED TO BURN   4.048 M-TONS OF TYPE  1 LOW SULFUR COAL IN YEAR  76


COLUMBIA               5540  01000
CURRENT HSC CENTS MBTU     0.5758E 02    DEMAND LSC MTONS      0.1875E 01      0.1875E 01      0.1223E 01
LSC FUEL               CENTS MBTU   64.7832    MILS KWHR    5.8305
ANNUAL CAPACITY FACTOR     0.750 SYSTEM PENALTY       0.39  MILS KWHR
LSC + HSC FUEL    CENTS MBTU   64.7759    MILS KWHR    5.8298    ANNUAL DOLLARS  0.201851E 08
CONVERSION COST    0.0            ANNUALIZED    0.0
ANNUAL TOTAL COST       0.215319E 08    MILS KWHR    6.2188
SCRUBBER(  1) CAP COST PER KW   45.5787    ANNUAL COST PER KW   16.9196
   S HANDLING0.595257E 01 O&M0.299074E 01 CAP CHG0.797627E 01 $ PER KW
ANNUAL CAPACITY FACTOR     0.750    SYSTEM PENALTY       1.24 MILS KWHR
ANNUAL FGD COST         0.155427E 08    MILS KWHR    4.4890    DOLLARS PER KW   29.4928  SIZE MW    502.111
ANNUAL FGD + HSC COST  0.334868E 08    MILS KWHR    9.6716
***** COLUMBIA    *****  IS ASSIGNED TO BURN   1.875 M-TONS OF TYPE  1 LOW SULFUR COAL IN YEAR  76


DUCK CR                0790  0 500
CURRENT HSC CENTS MBTU     0.5758E 02    DEMAND LSC MTONS      0.1423E 01      0.1423E 01      0.9286E 00
LSC FUEL               CENTS MBTU   69.9102    MILS KWHR    6.2919
ANNUAL CAPACITY FACTOR     0.750 SYSTEM PENALTY       0.39  MILS KWHR
LSC + HSC FUEL    CENTS MBTU   69.8977    MILS KWHR    6.2908    ANNUAL DOLLARS  0.165322E 08
CONVERSION COST    0.0            ANNUALIZED    0.0
ANNUAL TOTAL COST       0.175544E 08    MILS KWHR    6.6798
SCRUBBER(  1) CAP COST PER KW   49.5994    ANNUAL COST PER KW   17.9849
   S HANDLING0.595257E 01 O&M0.335246E 01 CAP CHG0.867990E 01 $ PER KW
ANNUAL CAPACITY FACTOR     0.750    SYSTEM PENALTY       1.24 MILS KWHR
ANNUAL FGD COST         0.123285E 08    MILS KWHR    4.6912    DOLLARS PER KW   30.8213  SIZE MW    381.109
ANNUAL FGD + HSC COST  0.259483E 08    MILS KWHR    9.8738
***** DUCK CR     *****  IS ASSIGNED TO BURN   1.423 M-TONS OF TYPE  2 LOW SULFUR COAL IN YEAR  76


SCHAHFER               3455  0 500
CURRENT HSC CENTS MBTU     0.5758E 02    DEMAND LSC MTONS      0.1236E 01      0.1236E 01      0.8063E 00
LSC FUEL               CENTS MBTU   70.5729    MILS KWHR    6.3516
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ANNUAL CAPACITY FACTOR     0.750 SYSTEM PENALTY        0.37  MILS KWHR
LSC + HSC FUEL    CENTS MBTU   70.0263    MILS KWHR    6.3024    ANNUAL DOLLARS  0.143819E 08
CONVERSION COST    0.0               ANNUALIZED    0.0
ANNUAL TOTAL COST        0.152330E 08    MILS KWHR    6.6754
SCRUBBER(  1) CAP COST PER KW   52.6919    ANNUAL COST PER KW   18.7854
   S HANDLING0.595258E 01 O&M0.361171E 01 CAP CHG0.922109E 01 $ PER KW
ANNUAL CAPACITY FACTOR     0.750    SYSTEM PENALTY        1.24 MILS KWHR
ANNUAL FGD COST          0.110519E 08    MILS KWHR     4.8431    DOLLARS PER KW   31.8194  SIZE MW    330.930
ANNUAL FGD + HSC COST  0.228785E 08    MILS KWHR   10.0257
***** SCHAHFER    ***** IS ASSIGNED TO BURN HIGH SULFUR COAL IN YEAR    76
  ITS DEMAND FOR LSC WAS     1.236M-TONS OR FOR SCRUBBERS WAS   330.930 MW


ERICKSON                 2605  0 500
CURRENT HSC CENTS MBTU     0.5758E 02    DEMAND LSC MTONS      0.5694E 00      0.5694E 00      0.3714E 00
LSC FUEL                 CENTS MBTU   79.8037    MILS KWHR     7.1823
ANNUAL CAPACITY FACTOR     0.750 SYSTEM PENALTY        0.37  MILS KWHR
LSC + HSC FUEL    CENTS MBTU   78.8687    MILS KWHR    7.0982    ANNUAL DOLLARS  0.746160E 07
CONVERSION COST    0.498117E 07    ANNUALIZED    0.871705E 06
ANNUAL TOTAL COST        0.872539E 07    MILS KWHR    8.3004
SCRUBBER(  1) CAP COST PER KW   67.7324    ANNUAL COST PER KW   23.0219
   S HANDLING0.595258E 01 O&M0.521619E 01 CAP CHG0.118532E 02 $ PER KW
ANNUAL CAPACITY FACTOR     0.750    SYSTEM PENALTY        1.24 MILS KWHR
ANNUAL FGD COST          0.593633E 07    MILS KWHR     5.6472    DOLLARS PER KW   37.1020  SIZE MW    152.444
ANNUAL FGD + HSC COST  0.113843E 08    MILS KWHR   10.8298
***** ERICKSON    *****  IS ASSIGNED TO BURN   0.371 M-TONS OF TYPE  3 LOW SULFUR COAL IN YEAR  76


COLLINS                  1115  01800
***** COLLINS     ***** IS ASSIGNED TO BURN HIGH SULFUR COAL IN YEAR    76
  ITS DEMAND FOR LSC WAS     0.0  M-TONS OR FOR SCRUBBERS WAS     0.0   MW
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I.D DEFINITION OF VARIABLES USED IN PLAN

1. Directory of COMMON Block Variables Listed by Block

a. Common /EX/

HTRAT(300)	-	heat rate (Btu/kwhr) for up to 300 plants
HSCOST(300)	-	cost of high sulfur coal (¢/Btux10^6)
MILES(300)	-	miles to each plant from nearest low sulfur coal field
FLGRT(300)	-	flue gas rate (scfm)
ECRAT(300)	-	concentration-emission ratio $\left(\frac{\mu g/m^3}{ton/day}\right)$
AGE(300)	-	average year when each of the (up to 300) plants was built
ESHFC	-	cost escalation factor for high sulfur coal
WETFR(300)	-	fraction of total capacity that has wet bottom design

b. Common /GP/

NCG	-	number of capacity groups
NCGM1	-	number of capacity groups minus 1
NAG	-	number of age groups
NAGM1	-	number of age groups minus 1
NMG	-	number of mine-mouth groups
NURG	-	number of urban-rural groups
NAQG	-	number of AQCR groups
NAGQM1	-	number of AQCR groups minus 1
PA(5,4)	-	priority level for each of four possible kinds of capacity, age, mine-mouth, urban-rural or AQCR groups
PLC(5,4), PSB(5,4)	-	group characteristics for low sulfur coal and for scrubbers, respectively: -1,2 = not possible; 0 = does not matter; 1 = desirable
CLIM(4)	-	upper limit capacity for each group
ALIM(4)	-	upper limit of year built for each group
MLIM(4)	-	upper mine-mouth index for each group

b. Common /GP/ (Contd.)

AQC(3,8)	-	list of AQCR numbers in each group (limit of 8 AQCRs for each group)

c. Common /LOCATE/

NAME(3,300)	-	name of each of the (up to 300) plants
CODE(3,300)	-	plant code numbers
STATE(300)	-	state number for each plant
AQCR(300)	-	AQCR number for each plant
COUNTY(300)	-	county name for each plant
MINEMO(300)	-	code of how close each plant is to a mine-mouth
URBAN(300)	-	U = urban, R = rural

d. Common /LSCOAL/

NLSC	-	number of low sulfur coal types
SUPLS(3)	-	supply of up to 3 different types of low sulfur coal for a given year
CMINE(3)	-	cost of mining, or mine-mouth cost ($/ton)
ESFACM(3)	-	cost escalation factor; percent of real cost increase each year for mine cost
CTRANS(3)	-	cost of transporting coal (mills/ton-mile)
ESFACT(3)	-	cost escalation factor; percent of real cost increase each year for transportation
BTULSC(3)	-	Btu/lb for each type of low sulfur coal
SULLSC(3)	-	percent sulfur by weight for each type of coal
IYRLS(3)	-	initial year in which each low sulfur coal type is available
SUPLSI(3)	-	initial supply of LSC available the first year (millions of tons)
SUSLSY(3,10)	-	supply of LSC available after first year for each year until the end of the study period (millions of tons)
ISRT(3)	-	type of relationship for coal supply on a year-by-year basis: 1 = supply given year by year 2 = % increase in available supply to be used in all years after the initial year 3 = % increase in previous year's demand to be used after the initial year
SPER(3)	-	percent increase to be used if ISRT types 2 or 3 are specified

e. Common /PLANT/

NPLANT	-	number of plants
CAP(300,12)	-	capacity in Mw for up to 300 plants for each of 12 years
BTUIN(300,12)	-	coal input needed ($Btux10^{13}/yr$)
SULPH(300)	-	% sulfur in coal presently burned
BTULB(300)	-	Btu/lb

f. Common /PRI/

ORDER(300)	-	index of plants arranged in order by priority and air quality
NPRIOR	-	number of different priority levels
MAXP	-	maximum priority level
MINP	-	minimum priority level
PRIOR(300)	-	priority level for each plant
PCOUNT(100)	-	number of plants at each priority level
LSCF(300), SCRF(300)	-	flag for each plant; whether or not it can utilize low sulfur coal or scrubbers, respectively: 0 = doesn't matter 1 = desirable 2 = cannot use 3 = scrubber assigned so no switching allowed

g. Common /SCRUBB/

ISRTS	-	scrubber supply relationship on year by year basis 1 = supply given year by year 2 = % increase of original supply to be used each year 3 = % increase of previous year's demand to be used
SPERS	-	% increase to be used if ISRTS = 2 or 3
IYRS	-	initial year when scrubbers are available
SUPSI	-	initial supply (Mw) of scrubbers available the first year
ESFSC	-	cost escalation factor
ISTYPE	-	number of types (5 possible types)

g. Common /SCRUBB/ (Contd.)

STYPE(5)	-	scrubber types to be considered (if more than one is given, the lowest cost one will be used) 1 = limestone 2 = lime 3 = M_gO 4 = caustic, with thermal regulator 5 = caustic, with electrostatic regulator
SUPSC(10)	-	supply of scrubbers (Mw) available after the initial year for each year to the end of the study period

h. Common /STRAT/

NSTRAT	-	number of strategies, limited to 20
SYR(20)	-	year of strategy implementation for each strategy
STAND(20)	-	air quality standard for each strategy (units depend on KIND (I))
KIND(20)	-	kind of units for each strategy: 1 = standard on primary emissions ($lbSO_2/MBtu$) 2 = standards on primary emissions $\left(\frac{lbSO_2}{day}\right)$ 3 = standards on concentration $\left(\frac{\mu g}{m^3}\right)$ 4 = standards to be calculated
STA(20)	-	state in which strategy applies
SAQ(20)	-	number of AQCRs in which strategy applies
SCOUN(20)	-	county in which strategy applies
SUR(20)	-	U or R if strategy applies to urban or rural plants
SCNUB(20)	-	minimum capacity of plants to which strategy applies
SCHMAX(20)	-	maximum capacity of plants to which strategy applies
SAMIN(20)	-	minimum year built of plants to which strategy applies
SAMAX (20)	-	maximum year built of plants to which strategy applies
AQS(20)	-	AQCRs in which strategy applies (no. given by SAQ (I))

i. Common /COMPLY/

TCOAL(12)	-	total LSC coal supply (Mtons) in each year
TSCR(12)	-	total scrubber supply (Mw) in each year
EXCOAL(12)	-	excess supply of LSC coal in each year
ASSIGN(300,12)	-	response assignment for each plant 1 = burns high sulfur coal 2 = burns low sulfur coal 3 = scrubber installed 4 = compliance not possible
LCOST(300,12)	-	cost (dollars) of low sulfur coal needed for compliance
FCOST(300,12)	-	cost (dollars) for scrubber needed for compliance

2. Non-common Variables

Definition of variables used throughout simulation (in approximate alphabetical order).

ANCOST	-	annual scrubber cost
AQDIF(300)	-	difference between plant emissions and air quality standards for up to 300 plants
AQSTD(300)	-	air quality standards for each plant
ADD	-	number of boilers for each plant
BTUI	-	plant input in $Btux10^{13}$/year
BCODE(10)	-	boiler codes for up to 10 boilers
BCAP(10)	-	boiler capacities
BUTIL(10)	-	% boiler utilizations
BAGE	-	average year plant was built in first year of study
BTU	-	$Btux10^{13}$/year
CAPACY	-	total plant capacity
COAL	-	% input Btu provided by coal
COST	-	cost of low sulfur coal
CAP	-	capacity in Mw
C1,C2,C3	-	plant code divided into 3 parts

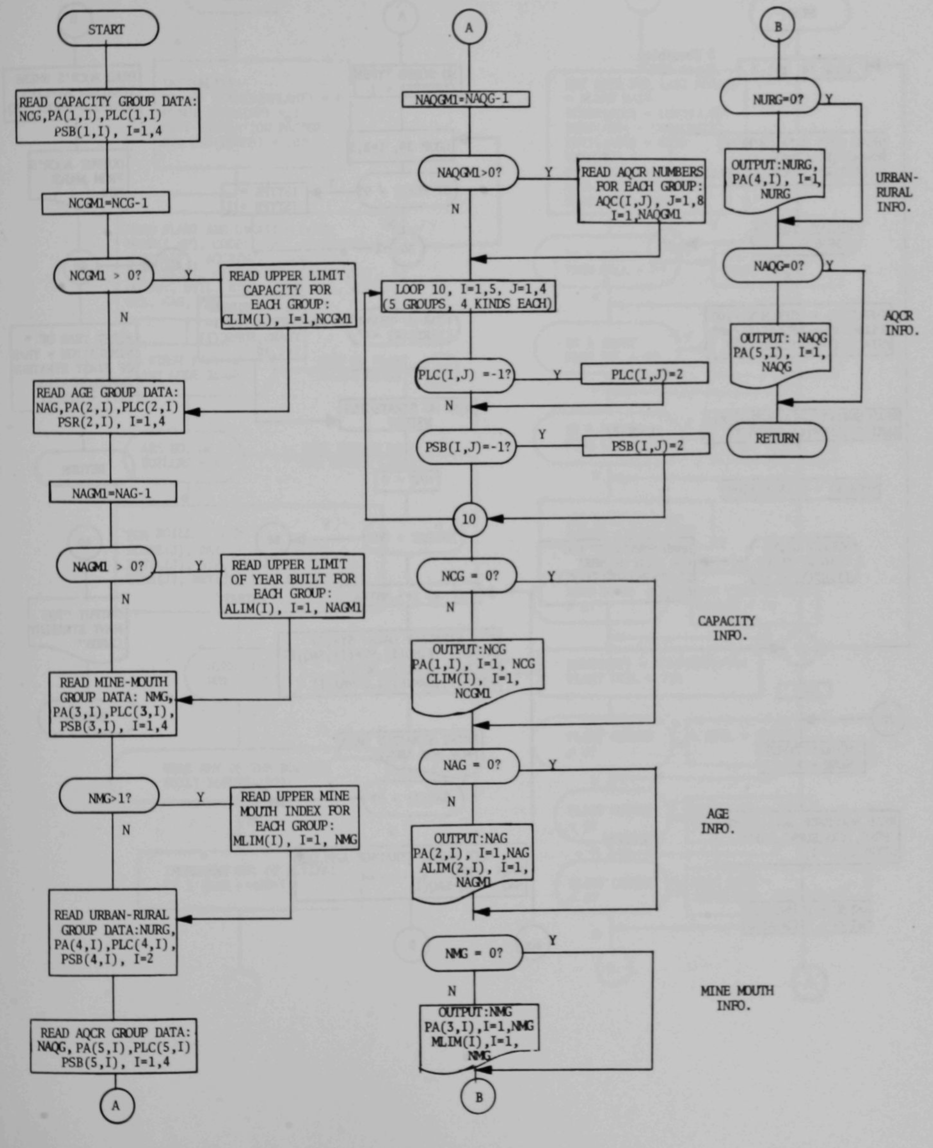
DAT(2)	-	month and year when plant was built
DATE(2,10)	-	months and years when each of up to 10 boilers were built
DCOAL(10)	-	if boilers use coal or not (=X, coal or blank)
DOIL(10)	-	if boilers use oil or not (=X, oil or blank)
DEAS(10)	-	if boilers use gas or not (=X, gas or blank)
DBTU	-	Btu for oil or gas
DBTUT	-	temporary Btu for oil or gas in retirement year
DEML(3,300)	-	demand at each plant for each of 3 types of LSC or
DEMS(300)	-	scrubbers respectively
DO	-	other direct costs for scrubbers, (site, handling, etc.)
DS(5)	-	retrofit cost for 5 scrubber types
DA(5)	-	alkali handling costs (5 scrubber types)
DSS	-	retrofit cost for scrubber installation including allowance for new plants
EXIST	-	if plant now exists or not, 1 = yes, 0 = no
ECAP(10)	-	capacity for a given boiler for given year
EXCAP	-	capacity adjustment between boilers for retirement
EMISH	-	sulfur emission ($lbSO_2/yr$)
EXDEM	-	amount by which demand for LSC of particular type exceeds supply
EFF	-	scrubber efficiency (.85)
EXP	-	exponent for handling cost calculation
EAGE	-	average year plant was built in last year of study
FRACL	-	fraction of capacity of plant to be supplied with LSC
FRACS	-	fraction of capacity of plant to be scrubbed
FS	-	economies of scale of scrubbers (Mw)
FR	-	difficulty of retrofit ($1 \leq FR \leq 1.5$)
FA	-	economies of scale for handling lime or limestone (tons S/hr)
GAS	-	% input Btu provided by natural gas

INTY	-	year of implementation of first strategy (first year of simulation)
IN	-	if plant fits given strategy: 1 = yes, 0 = no
IY	-	index of year of study (IYEAR-70)
IC	-	contractor indirect costs for scrubber installation
IU	-	user indirect costs for scrubbers
IYEAR	-	year of study = 71,72,...,82
KOG	-	if plant has boilers burning coal and some other fuel: 0 = just coal 1 = combination of fuels 2 = combination boilers in year of change
LEFT	-	amount of LSC remaining of particular type
LO	-	operating labor cost for scrubber installation
LF	-	load factor
MPART	-	month when boiler was built
MAN	-	% maintenance (.075) cost for scrubbers
NAQ	-	index of AQCRs which apply to given strategy
N	-	(in SR/SCRUBC) number of module scrubbers; also used as plant index in other subroutines
NP	-	plant index ($1 \leq NP \leq 300$)
OIL	-	% input Btu provided by oil
OUTPUT	-	plant output ($kwhr \times 10^6$)
PUTIL	-	% utilization of plant
PFLAG	-	error flag for priority levels
PARTSP	-	partial supply of LSC
Q	-	flue gas rate in scfm
RC	-	annual capital charge rate

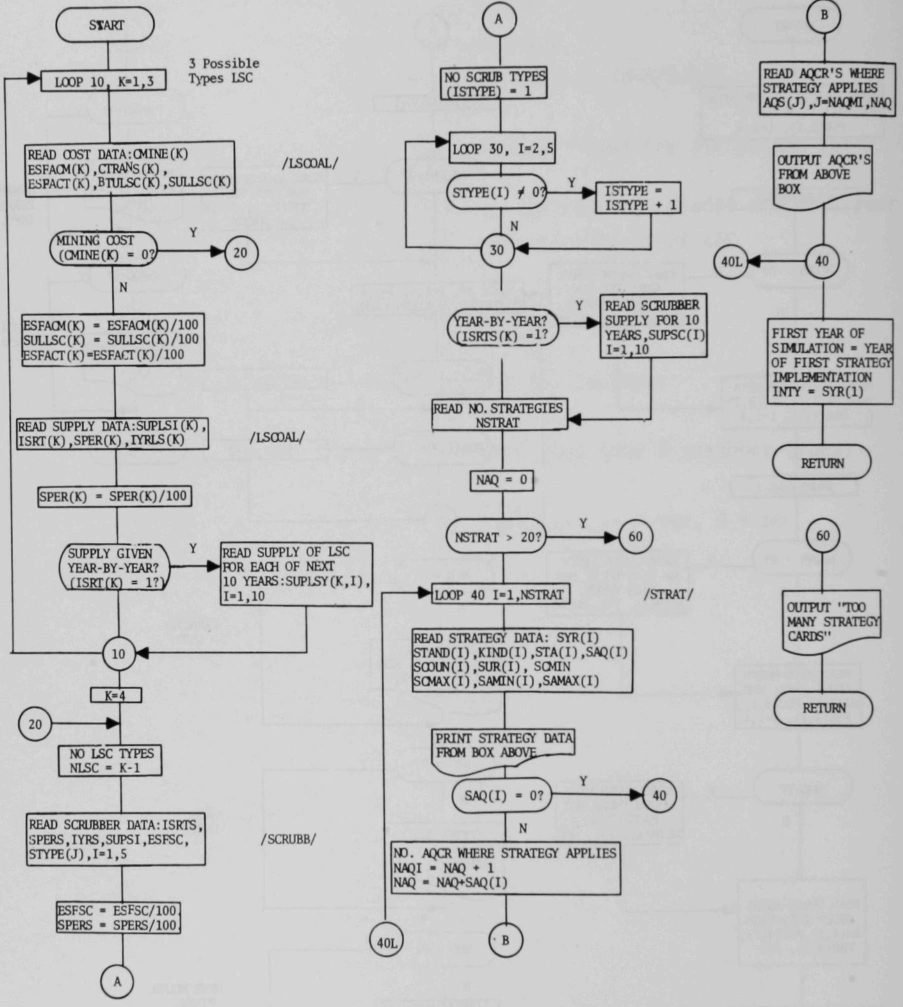
SUPSCR	-	supply of scrubbers
SULH	-	lb sulfur/Btu for HSC
SULL	-	lb sulfur/Btu for LSC
SCOST	-	cost of scrubbers
STYPE	-	type of scrubbers
SULFY	-	sulfur in tons/year
SR	-	rate of sulfur removal (lbS/kwhr)
TSBTU(12)	-	total input (Btux10^{13}/yr) for all plants for each year
TCAP(12)	-	total capacity (Mw) for all plants for each year
TOTSUP	-	total supply of all 3 kinds of LSC
UTIL	-	plant utilization (load factor)
USED	-	amount of LSC used
US	-	scrubbing costs \$.77/scfm-yr
VA(5)	-	alkali handling costs (for 5 scrubber types)
WET(10)	-	if wet bottom boiler: 1 = yes, 0 = no
WCAP	-	wet capacity

I.E. DETAILED FLOWCHARTS OF EACH SUBROUTINE

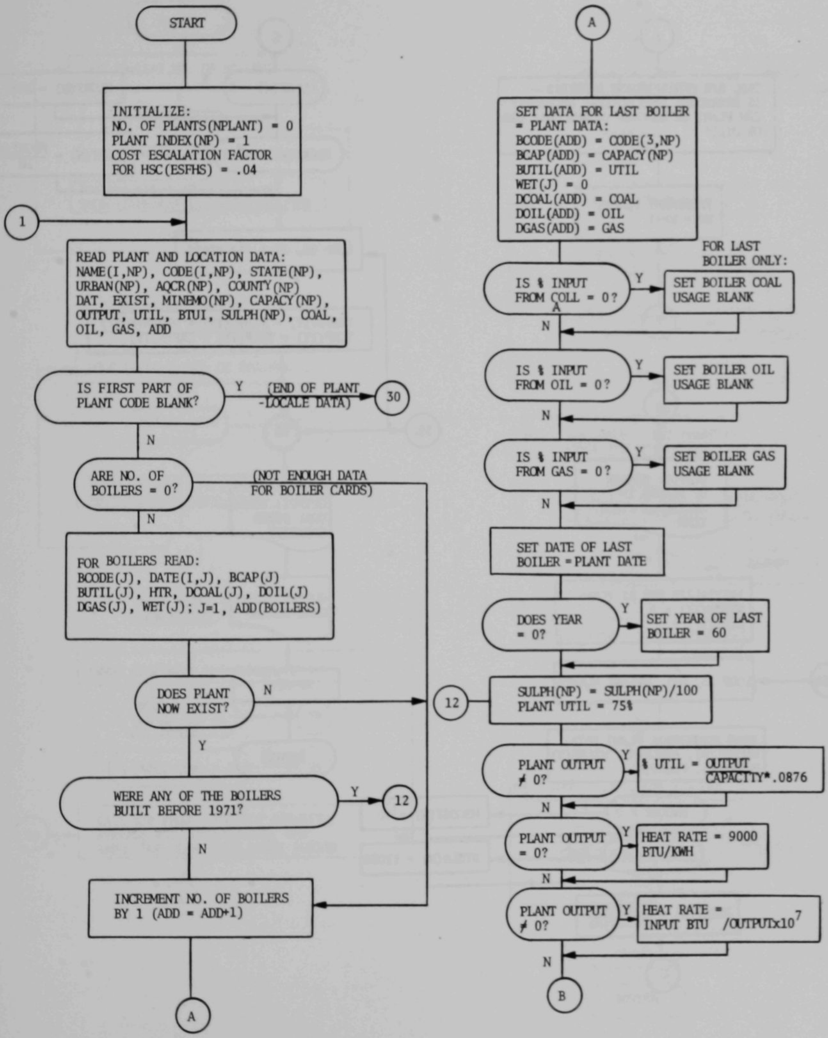
S/R GROUP /GP/



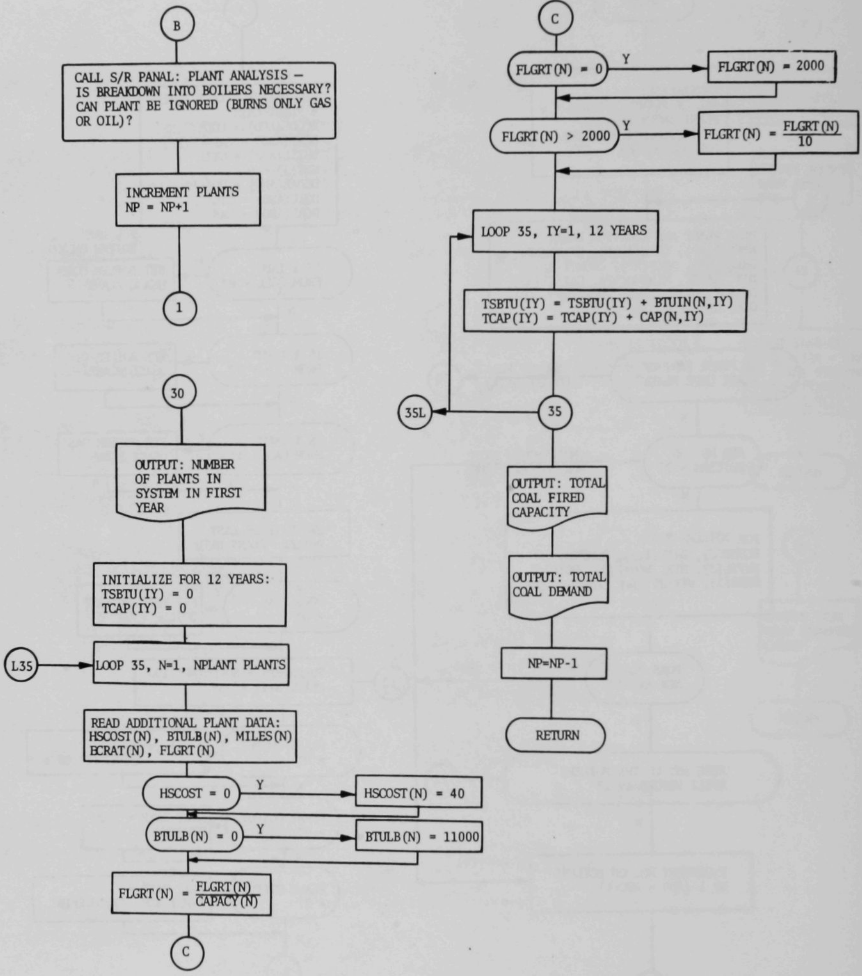
S/R RSUP /LSCOAL,SCRUBB,STRAT/



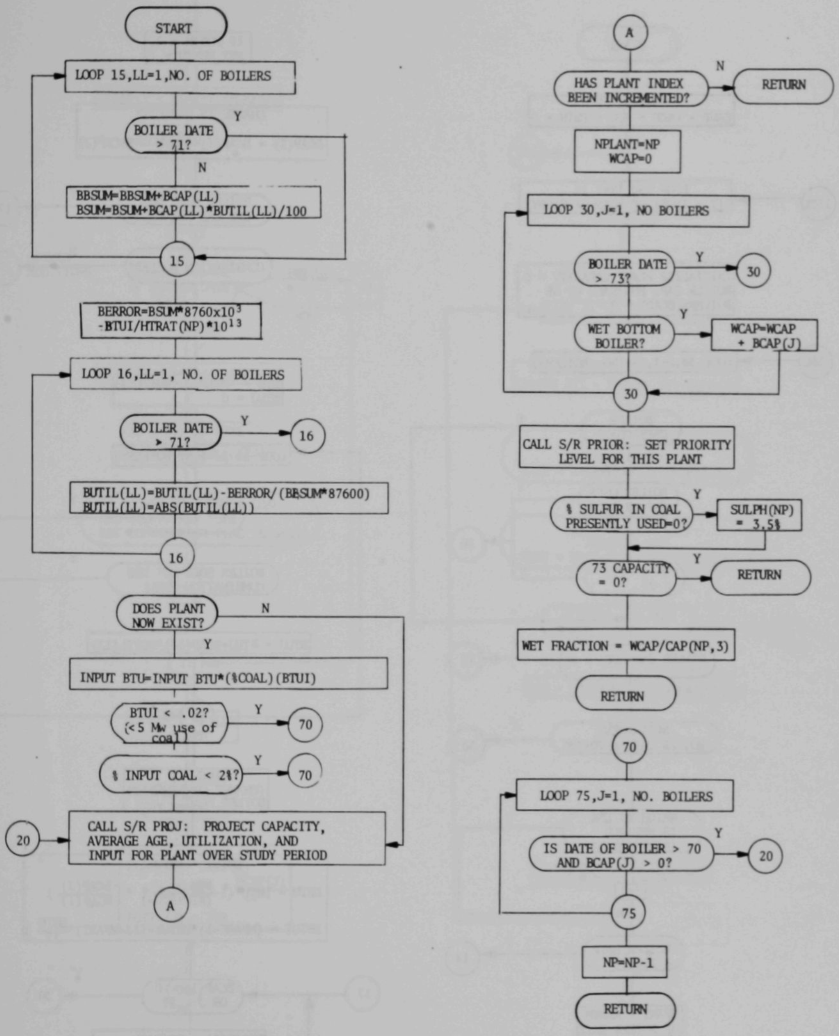
S/R RPLANT /PLANT,EX,LOCATE/

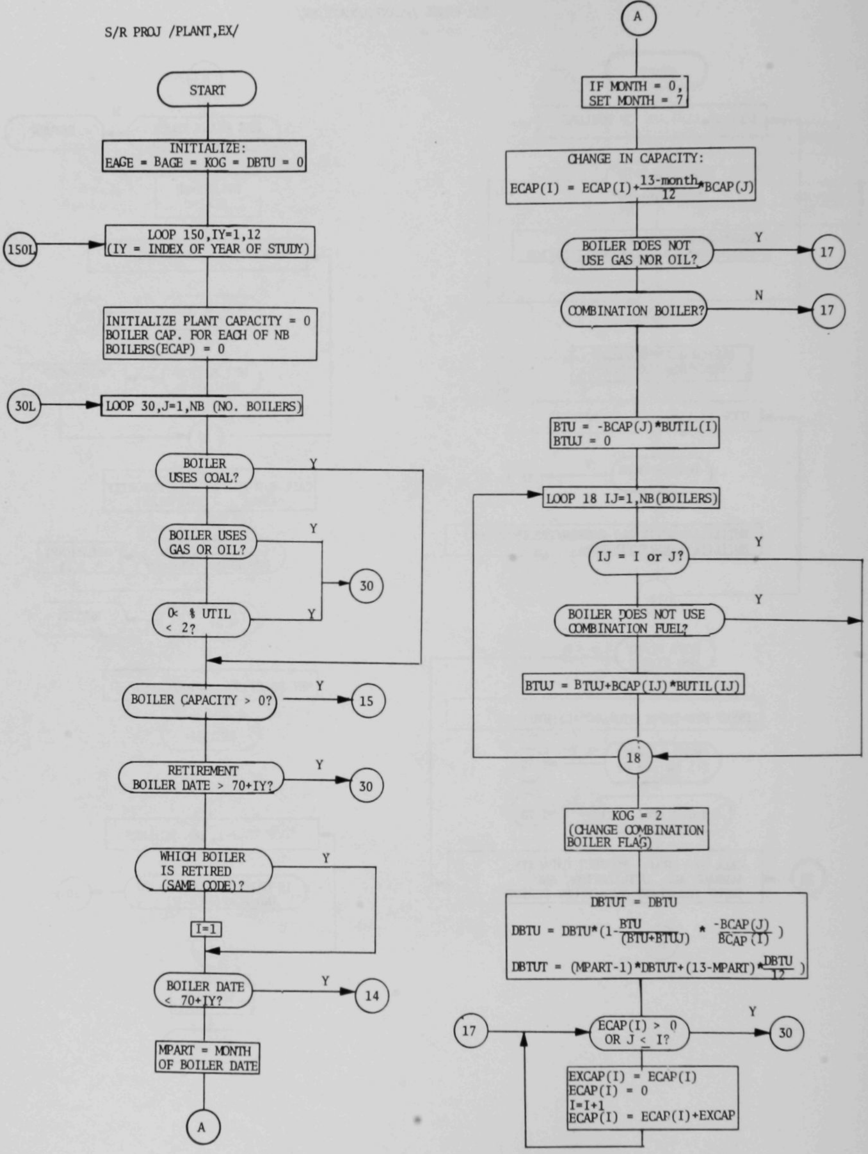


S/R RPLANT

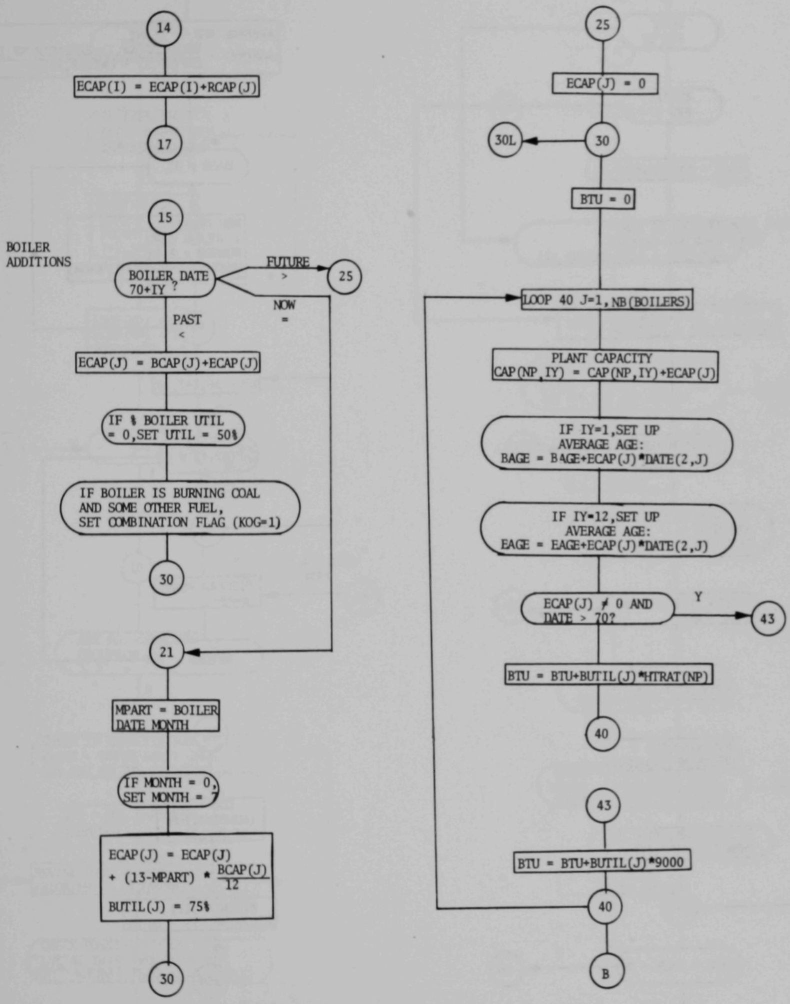

B
CALL S/R PANAL: PLANT ANALYSIS — IS BREAKDOWN INTO BOILERS NECESSARY? CAN PLANT BE IGNORED (BURNS ONLY GAS OR OIL)?
INCREMENT PLANTS NP = NP+1
1
30
OUTPUT: NUMBER OF PLANTS IN SYSTEM IN FIRST YEAR
INITIALIZE FOR 12 YEARS: TSBTU(IY) = 0 TCAP(IY) = 0
L35
LOOP 35, N=1, NPLANT PLANTS
READ ADDITIONAL PLANT DATA: HSCOST(N), BTULB(N), MILES(N) BCRAT(N), FLGRT(N)
HSCOST = 0
Y
HSCOST(N) = 40
BTULB(N) = 0
Y
BTULB(N) = 11000
FLGRT(N) = FLGRT(N) / CAPACY(N)
C
C
FLGRT(N) = 0
Y
FLGRT(N) = 2000
FLGRT(N) > 2000
Y
FLGRT(N) = FLGRT(N) / 10
LOOP 35, IY=1, 12 YEARS
TSBTU(IY) = TSBTU(IY) + BTUIN(N,IY)
TCAP(IY) = TCAP(IY) + CAP(N,IY)
35L
35
OUTPUT: TOTAL COAL FIRED CAPACITY
OUTPUT: TOTAL COAL DEMAND
NP=NP-1
RETURN

S/R PANEL /PLANT,LOCATE,EX/

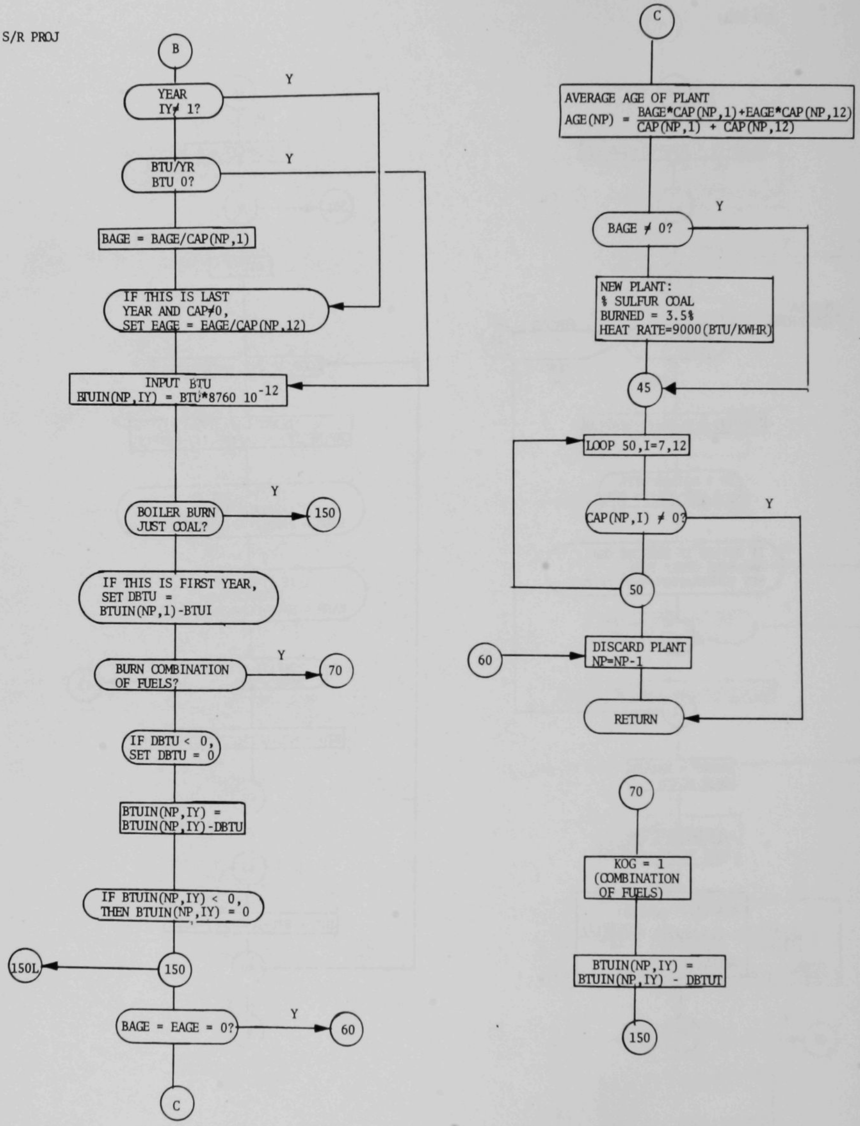



S/R PROJ /PLANT,EX/
START
INITIALIZE:
EAGE = BAGE = KOG = DBTU = 0
150L
LOOP 150,IY=1,12
(IY = INDEX OF YEAR OF STUDY)
INITIALIZE PLANT CAPACITY = 0
BOILER CAP. FOR EACH OF NB
BOILERS(ECAP) = 0
30L
LOOP 30,J=1,NB (NO. BOILERS)
BOILER
USES COAL?
Y
BOILER USES
GAS OR OIL?
Y
30
0< % UTIL
< 2?
Y
BOILER CAPACITY > 0?
Y
15
RETIREMENT
BOILER DATE > 70+IY?
Y
30
WHICH BOILER
IS RETIRED
(SAME CODE)?
Y
I=1
BOILER DATE
< 70+IY?
Y
14
MPART = MONTH
OF BOILER DATE
A
A
IF MONTH = 0,
SET MONTH = 7
CHANGE IN CAPACITY:
ECAP(I) = ECAP(I)+13-month/12*BCAP(J)
BOILER DOES NOT
USE GAS NOR OIL?
Y
17
COMBINATION BOILER?
N
17
BTU = -BCAP(J)*BUTIL(I)
BTUJ = 0
LOOP 18 IJ=1,NB(BOILERS)
IJ = I or J?
Y
BOILER DOES NOT USE
COMBINATION FUEL?
Y
BTUJ = BTUJ+BCAP(IJ)*BUTIL(IJ)
18
KOG = 2
(CHANGE COMBINATION
BOILER FLAG)
DBTUT = DBTU
DBTU = DBTU*(1-BTU/(BTU+BTUJ) * -BCAP(J)/BCAP(I))
DBTUT = (MPART-1)*DBTUT+(13-MPART)*DBTU/12)
17
ECAP(I) > 0
OR J ≤ I?
Y
30
EXCAP(I) = ECAP(I)
ECAP(I) = 0
I=I+1
ECAP(I) = ECAP(I)+EXCAP

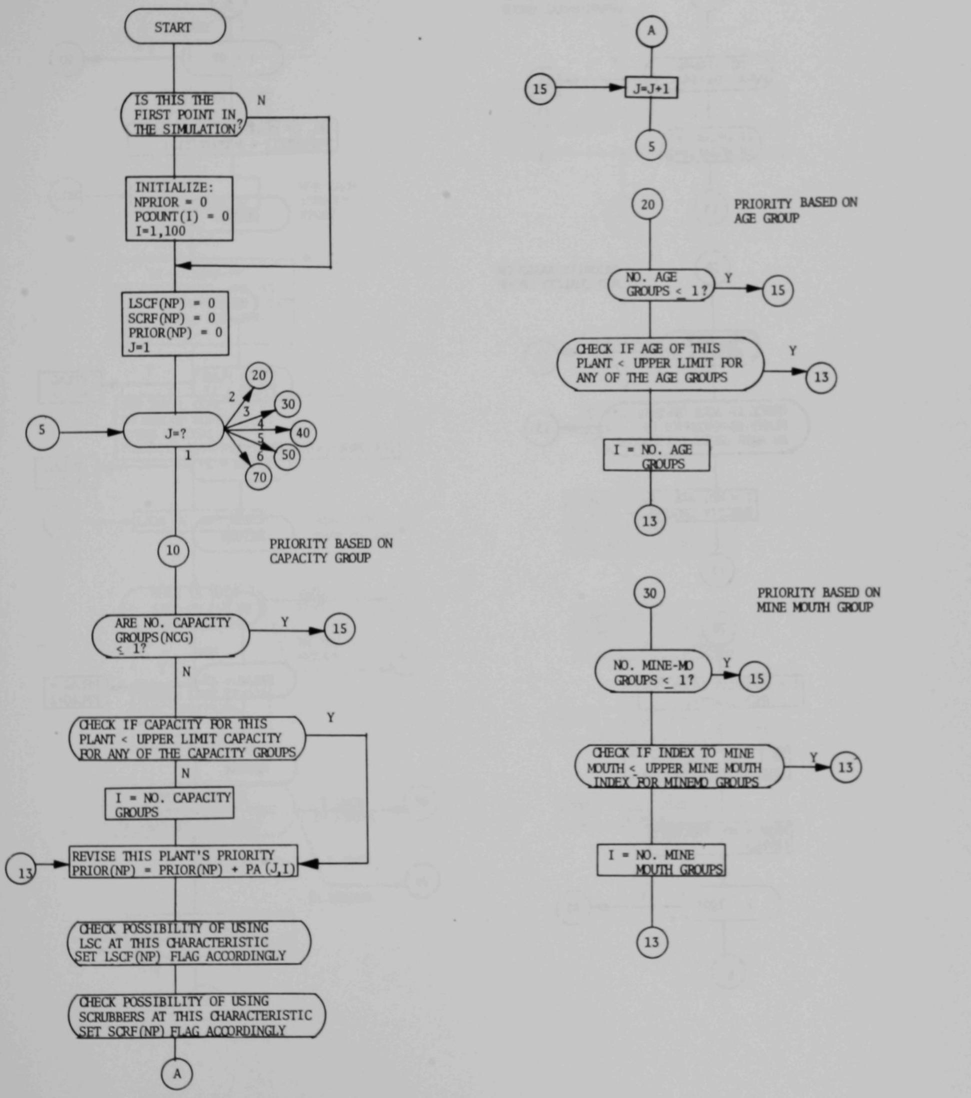
S/R PROJ


14
ECAP(I) = ECAP(I)+RCAP(J)
17
15
BOILER
ADDITIONS
BOILER DATE
70+IY ?
FUTURE
>
25
NOW
=
PAST
<
ECAP(J) = BCAP(J)+ECAP(J)
IF % BOILER UTIL
= 0,SET UTIL = 50%
IF BOILER IS BURNING COAL
AND SOME OTHER FUEL,
SET COMBINATION FLAG (KOG=1)
30
21
MPART = BOILER
DATE MONTH
IF MONTH = 0,
SET MONTH = 7
ECAP(J) = ECAP(J)
+ (13-MPART) * BCAP(J)/12
BUTIL(J) = 75%
30
25
ECAP(J) = 0
30L
30
BTU = 0
LOOP 40 J=1,NB(BOILERS)
PLANT CAPACITY
CAP(NP,IY) = CAP(NP,IY)+ECAP(J)
IF IY=1,SET UP
AVERAGE AGE:
BAGE = BAGE+ECAP(J)*DATE(2,J)
IF IY=12,SET UP
AVERAGE AGE:
EAGE = EAGE+ECAP(J)*DATE(2,J)
ECAP(J) ≠ 0 AND
DATE > 70?
Y
43
BTU = BTU+BUTIL(J)*HTRAT(NP)
40
43
BTU = BTU+BUTIL(J)*9000
40
B

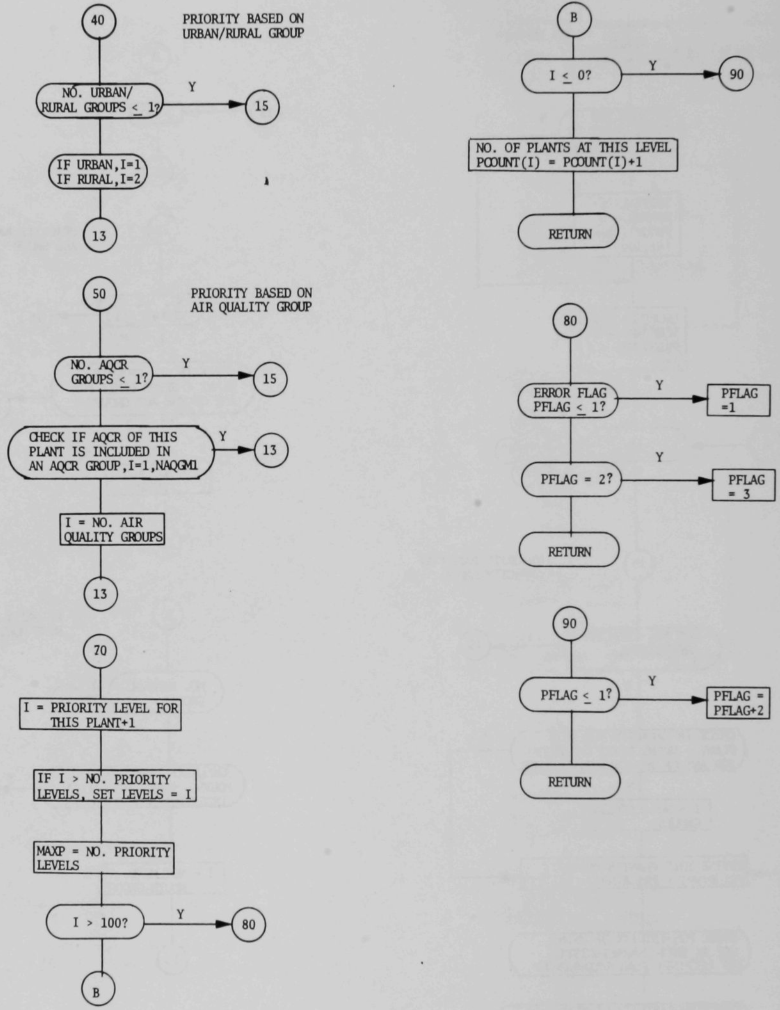
S/R PROJ


B
YEAR IY≠ 1?
Y
BTU/YR BTU 0?
Y
BAGE = BAGE/CAP(NP,1)
IF THIS IS LAST YEAR AND CAP≠0, SET EAGE = EAGE/CAP(NP,12)
INPUT BTU
BTUIN(NP,IY) = BTU*8760 10^-12
BOILER BURN JUST COAL?
Y
150
IF THIS IS FIRST YEAR, SET DBTU = BTUIN(NP,1)-BTUI
BURN COMBINATION OF FUELS?
Y
70
IF DBTU < 0, SET DBTU = 0
BTUIN(NP,IY) = BTUIN(NP,IY)-DBTU
IF BTUIN(NP,IY) < 0, THEN BTUIN(NP,IY) = 0
150L
150
BAGE = EAGE = 0?
Y
60
C
C
AVERAGE AGE OF PLANT
AGE(NP) = BAGE*CAP(NP,1)+EAGE*CAP(NP,12) / CAP(NP,1) + CAP(NP,12)
BAGE ≠ 0?
Y
NEW PLANT:
% SULFUR COAL
BURNED = 3.5%
HEAT RATE=9000(BTU/KWHR)
45
LOOP 50,I=7,12
CAP(NP,I) ≠ 0?
Y
50
60
DISCARD PLANT NP=NP-1
RETURN
70
KOG = 1 (COMBINATION OF FUELS)
BTUIN(NP,IY) = BTUIN(NP,IY) - DBTUT
150

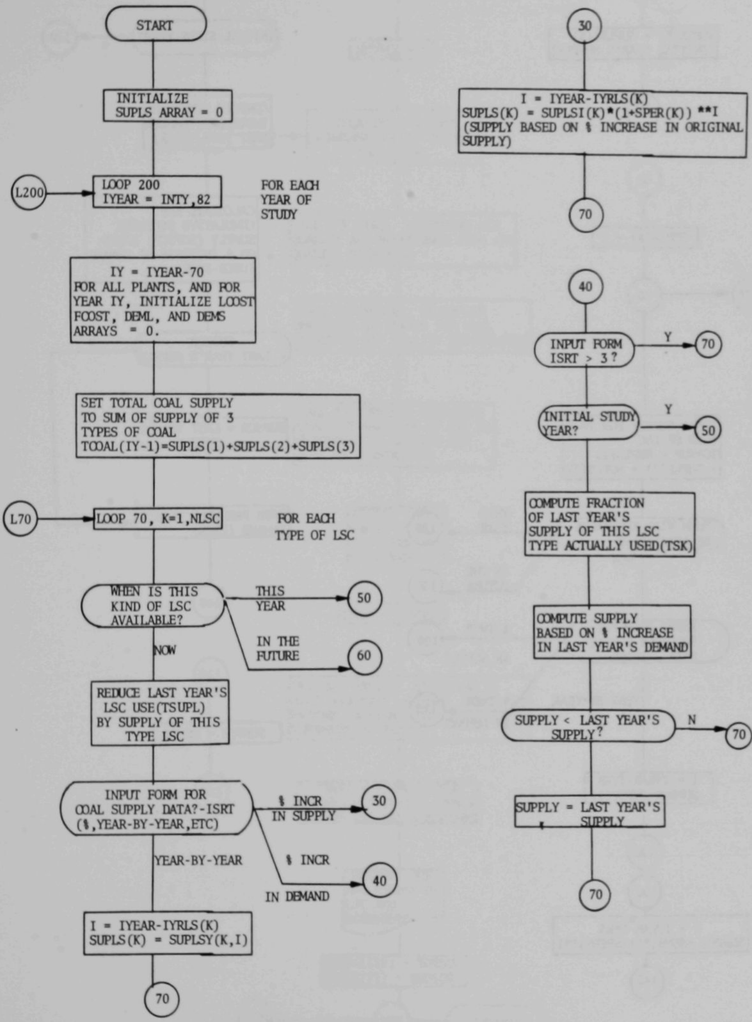
S/R PRIOR /GP,PRI/



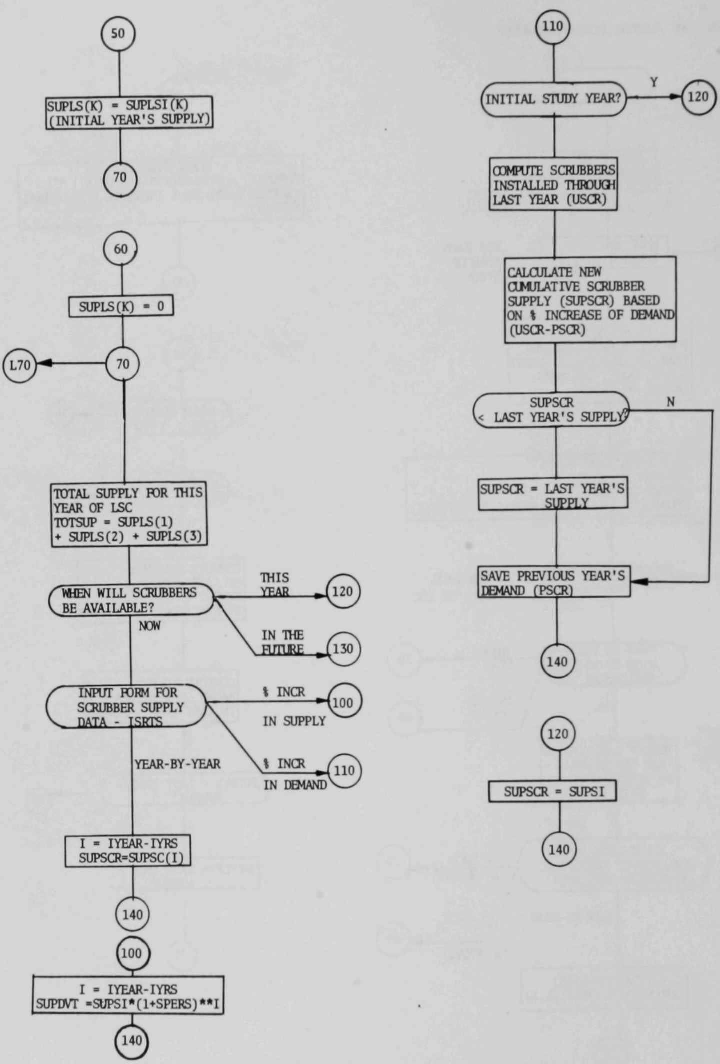
S/R PRIOR


40
PRIORITY BASED ON URBAN/RURAL GROUP
NO. URBAN/ RURAL GROUPS ≤ 1?
Y
15
IF URBAN, I=1
IF RURAL, I=2
13
50
PRIORITY BASED ON AIR QUALITY GROUP
NO. AQCR GROUPS ≤ 1?
Y
15
CHECK IF AQCR OF THIS PLANT IS INCLUDED IN AN AQCR GROUP, I=1, NAQGM1
Y
13
I = NO. AIR QUALITY GROUPS
13
70
I = PRIORITY LEVEL FOR THIS PLANT+1
IF I > NO. PRIORITY LEVELS, SET LEVELS = I
MAXP = NO. PRIORITY LEVELS
I > 100?
Y
80
B
B
I ≤ 0?
Y
90
NO. OF PLANTS AT THIS LEVEL
PCOUNT(I) = PCOUNT(I)+1
RETURN
80
ERROR FLAG PFLAG ≤ 1?
Y
PFLAG =1
PFLAG = 2?
Y
PFLAG = 3
RETURN
90
PFLAG ≤ 1?
Y
PFLAG = PFLAG+2
RETURN

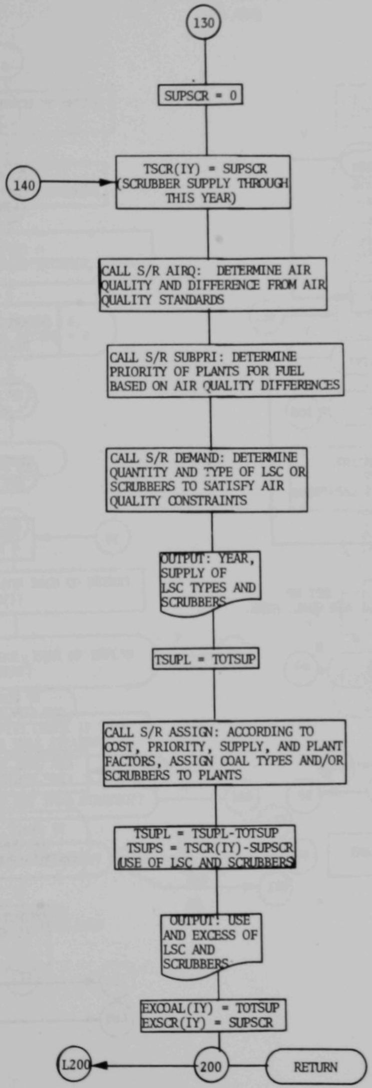
S/R SIMU /LSCOAL,SCRUBB, COMPLY/



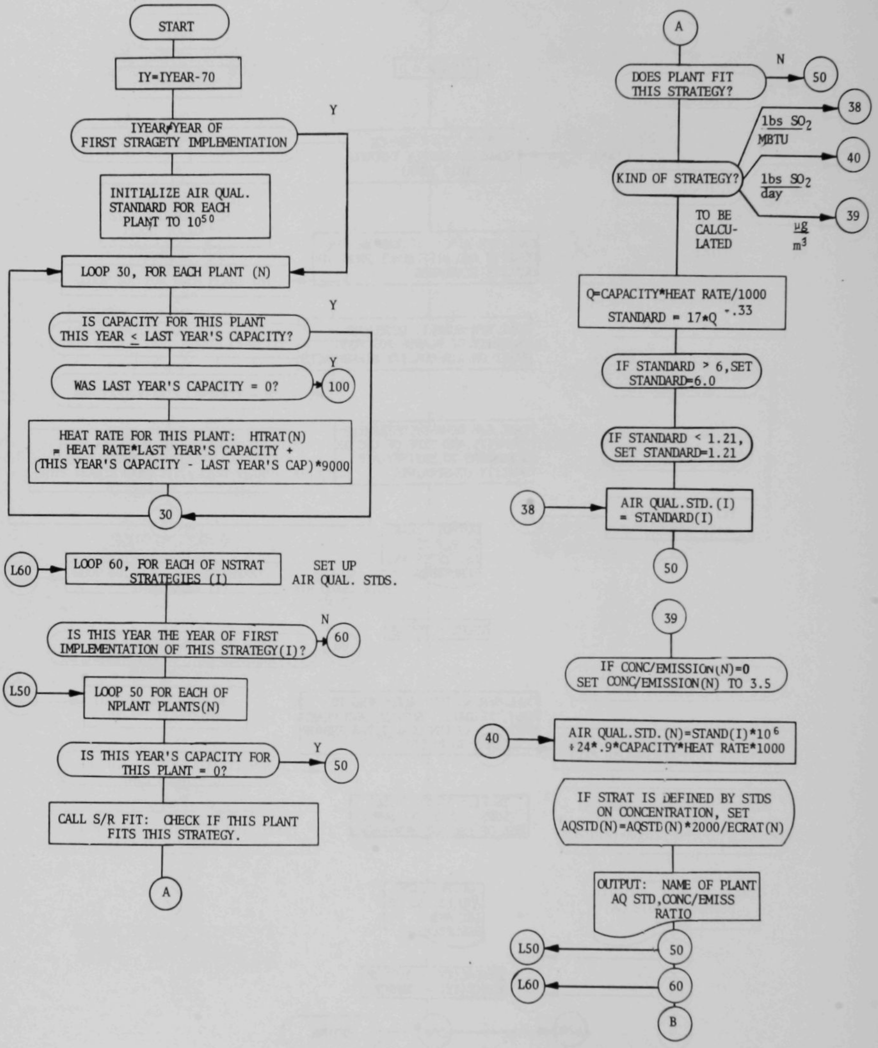
S/R SIMU


50
SUPLS(K) = SUPLSI(K)
(INITIAL YEAR'S SUPPLY)
70
60
SUPLS(K) = 0
L70
70
TOTAL SUPPLY FOR THIS YEAR OF LSC
TOTSUP = SUPLS(1) + SUPLS(2) + SUPLS(3)
WHEN WILL SCRUBBERS BE AVAILABLE?
THIS YEAR
120
NOW
IN THE FUTURE
130
INPUT FORM FOR SCRUBBER SUPPLY DATA - ISRTS
% INCR IN SUPPLY
100
% INCR IN DEMAND
110
YEAR-BY-YEAR
I = IYEAR-IYRS
SUPSCR=SUPSC(I)
140
100
I = IYEAR-IYRS
SUPDVT =SUPSI*(1+SPERS)**I
140
110
INITIAL STUDY YEAR?
Y
120
COMPUTE SCRUBBERS INSTALLED THROUGH LAST YEAR (USCR)
CALCULATE NEW CUMULATIVE SCRUBBER SUPPLY (SUPSCR) BASED ON % INCREASE OF DEMAND (USCR-PSCR)
SUPSCR < LAST YEAR'S SUPPLY?
N
SUPSCR = LAST YEAR'S SUPPLY
SAVE PREVIOUS YEAR'S DEMAND (PSCR)
140
120
SUPSCR = SUPSI
140

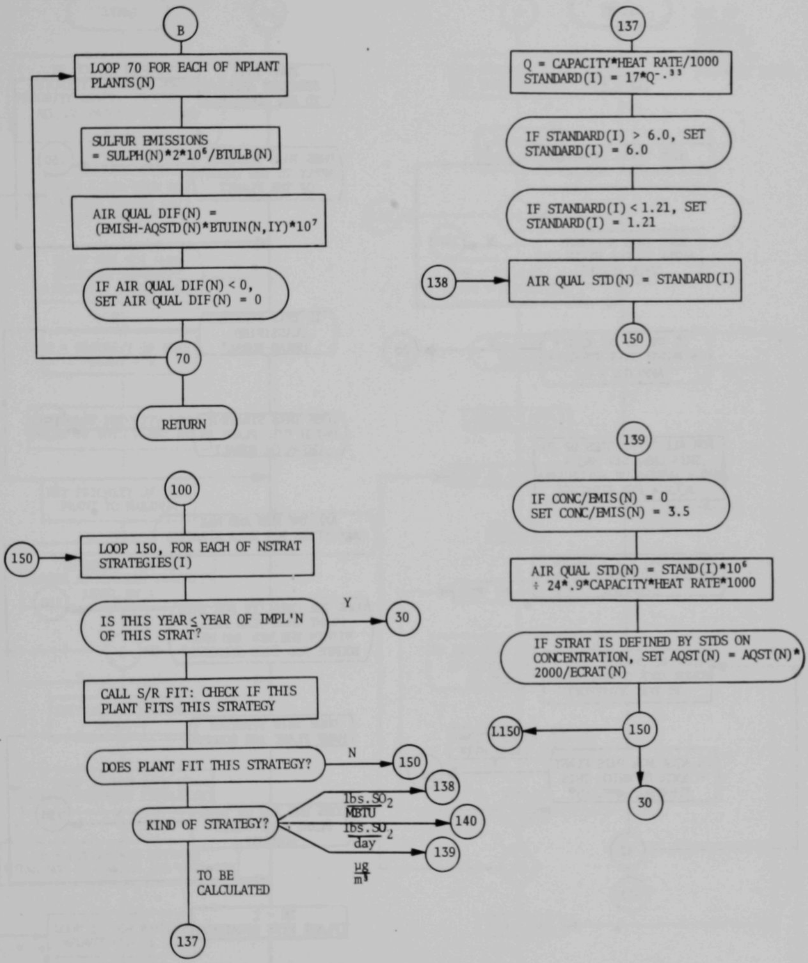
S/R SIMU


130
SUPSCR = 0
140
TSCR(IY) = SUPSCR (SCRUBBER SUPPLY THROUGH THIS YEAR)
CALL S/R AIRQ: DETERMINE AIR QUALITY AND DIFFERENCE FROM AIR QUALITY STANDARDS
CALL S/R SUBPRI: DETERMINE PRIORITY OF PLANTS FOR FUEL BASED ON AIR QUALITY DIFFERENCES
CALL S/R DEMAND: DETERMINE QUANTITY AND TYPE OF LSC OR SCRUBBERS TO SATISFY AIR QUALITY CONSTRAINTS
OUTPUT: YEAR, SUPPLY OF LSC TYPES AND SCRUBBERS
TSUPL = TOTSUP
CALL S/R ASSIGN: ACCORDING TO COST, PRIORITY, SUPPLY, AND PLANT FACTORS, ASSIGN COAL TYPES AND/OR SCRUBBERS TO PLANTS
TSUPL = TSUPL-TOTSUP
TSUPS = TSCR(IY)-SUPSCR
(USE OF LSC AND SCRUBBERS)
OUTPUT: USE AND EXCESS OF LSC AND SCRUBBERS
EXCOAL(IY) = TOTSUP
EXSCR(IY) = SUPSCR
L200
200
RETURN

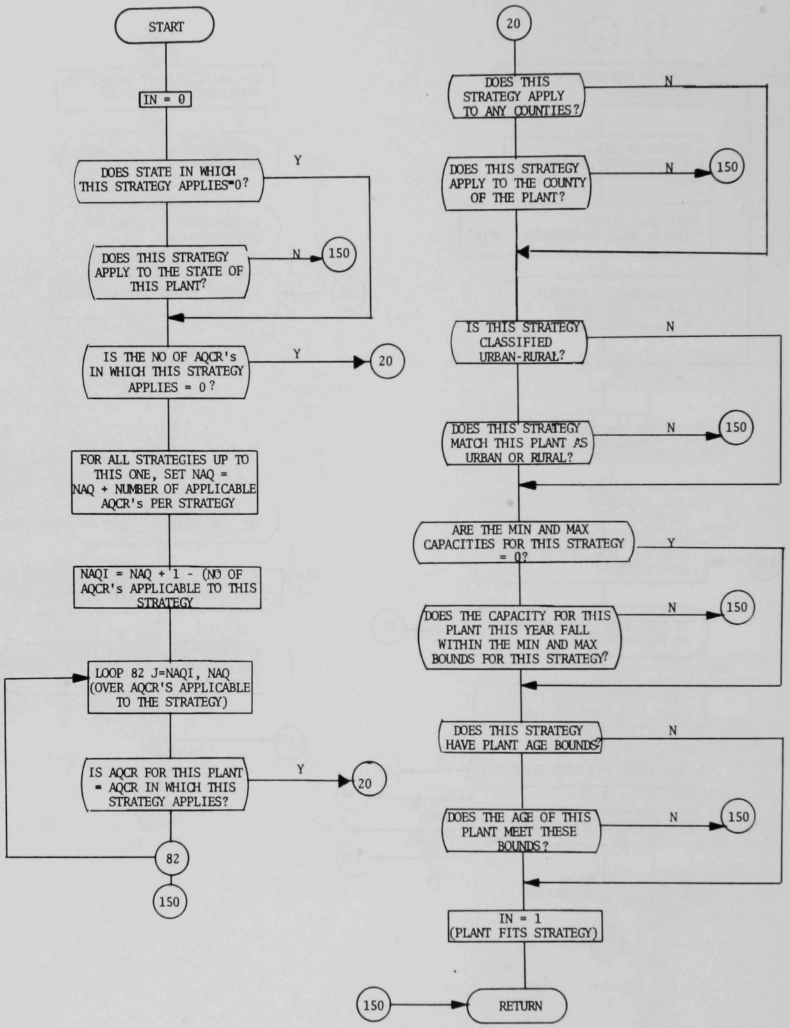
S/R AIRQ /LOCATE,PLANT,EX,STRAT/



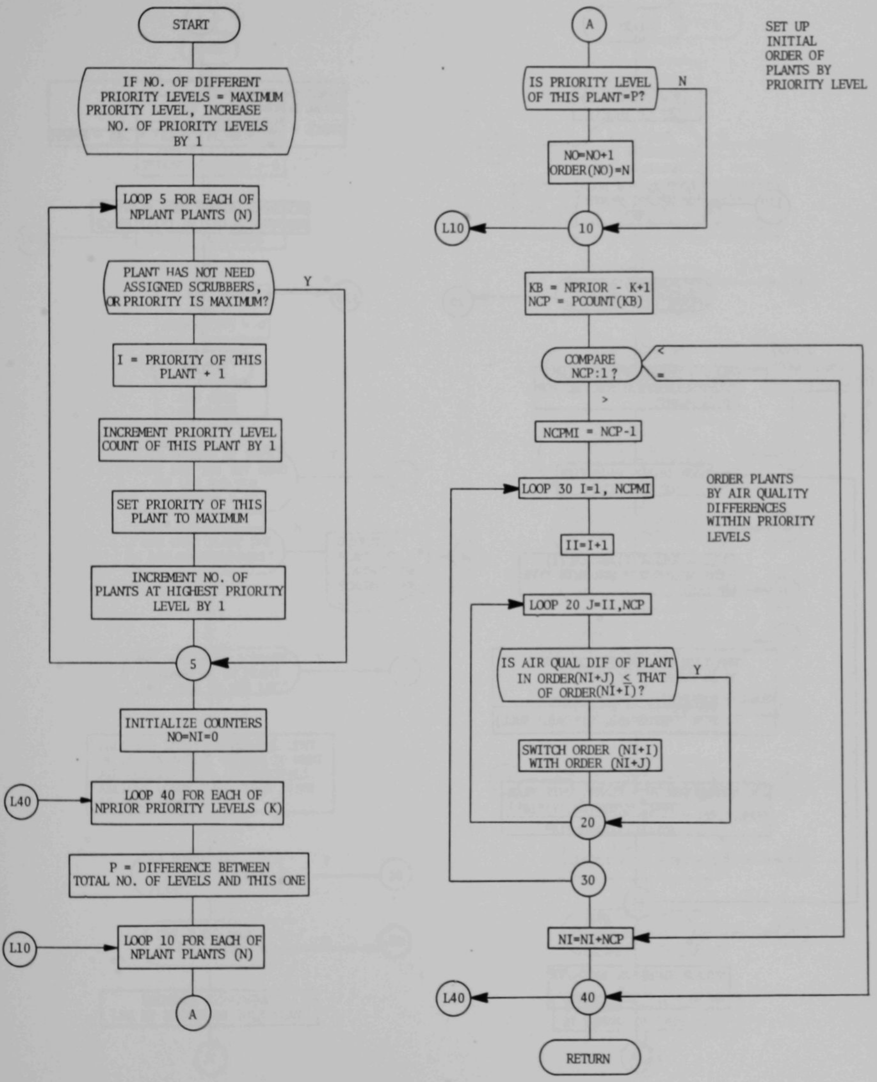
S/R AIRQ


B
LOOP 70 FOR EACH OF NPLANT PLANTS(N)
SULFUR EMISSIONS = SULPH(N)*2*10⁶/BTULB(N)
AIR QUAL DIF(N) = (EMISH-AQSTD(N)*BTUIN(N,IY)*10⁷
IF AIR QUAL DIF(N) < 0, SET AIR QUAL DIF(N) = 0
70
RETURN
100
150
LOOP 150, FOR EACH OF NSTRAT STRATEGIES(I)
IS THIS YEAR ≤ YEAR OF IMPL'N OF THIS STRAT?
Y
30
CALL S/R FIT: CHECK IF THIS PLANT FITS THIS STRATEGY
DOES PLANT FIT THIS STRATEGY?
N
150
KIND OF STRATEGY?
lbs.SO2/MBTU
138
lbs.SO2/day
140
μg/m³
139
TO BE CALCULATED
137
137
Q = CAPACITY*HEAT RATE/1000
STANDARD(I) = 17*Q⁻·³³
IF STANDARD(I) > 6.0, SET STANDARD(I) = 6.0
IF STANDARD(I) < 1.21, SET STANDARD(I) = 1.21
138
AIR QUAL STD(N) = STANDARD(I)
150
139
IF CONC/EMIS(N) = 0 SET CONC/EMIS(N) = 3.5
AIR QUAL STD(N) = STAND(I)*10⁶ ÷ 24*.9*CAPACITY*HEAT RATE*1000
IF STRAT IS DEFINED BY STDS ON CONCENTRATION, SET AQST(N) = AQST(N)*2000/ECRAT(N)
L150
150
30

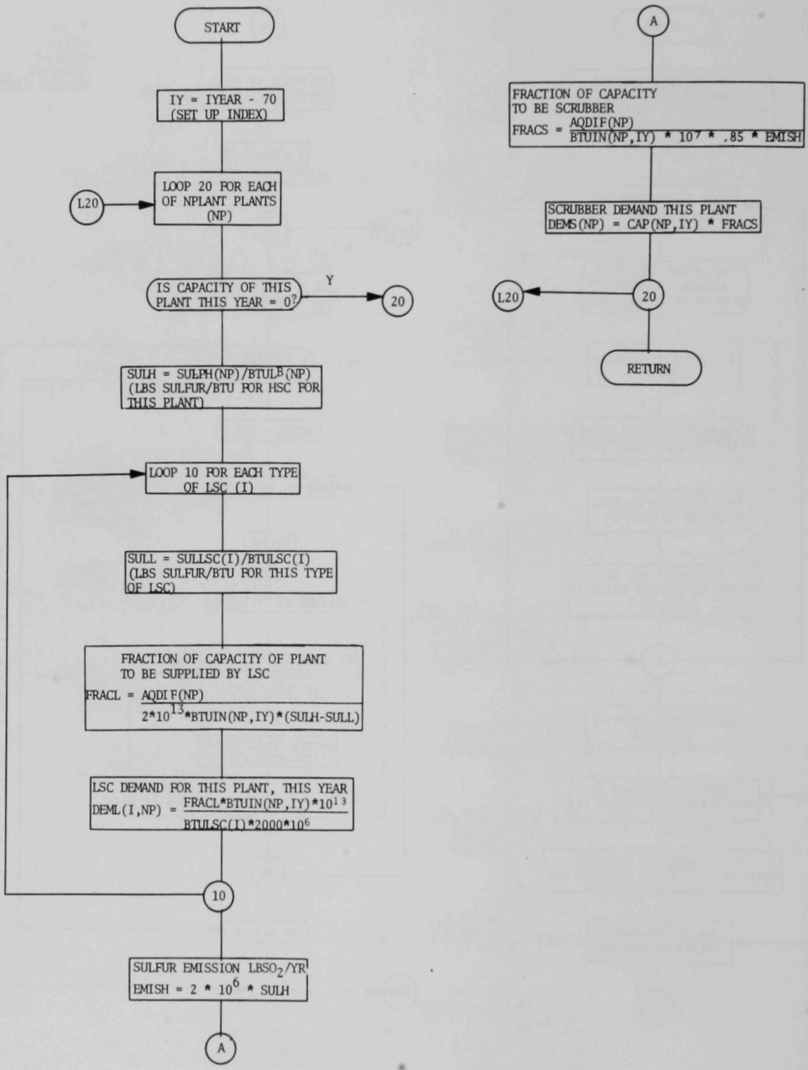
S/R FIT/LOCATE, STRAT, PLANT, EX/



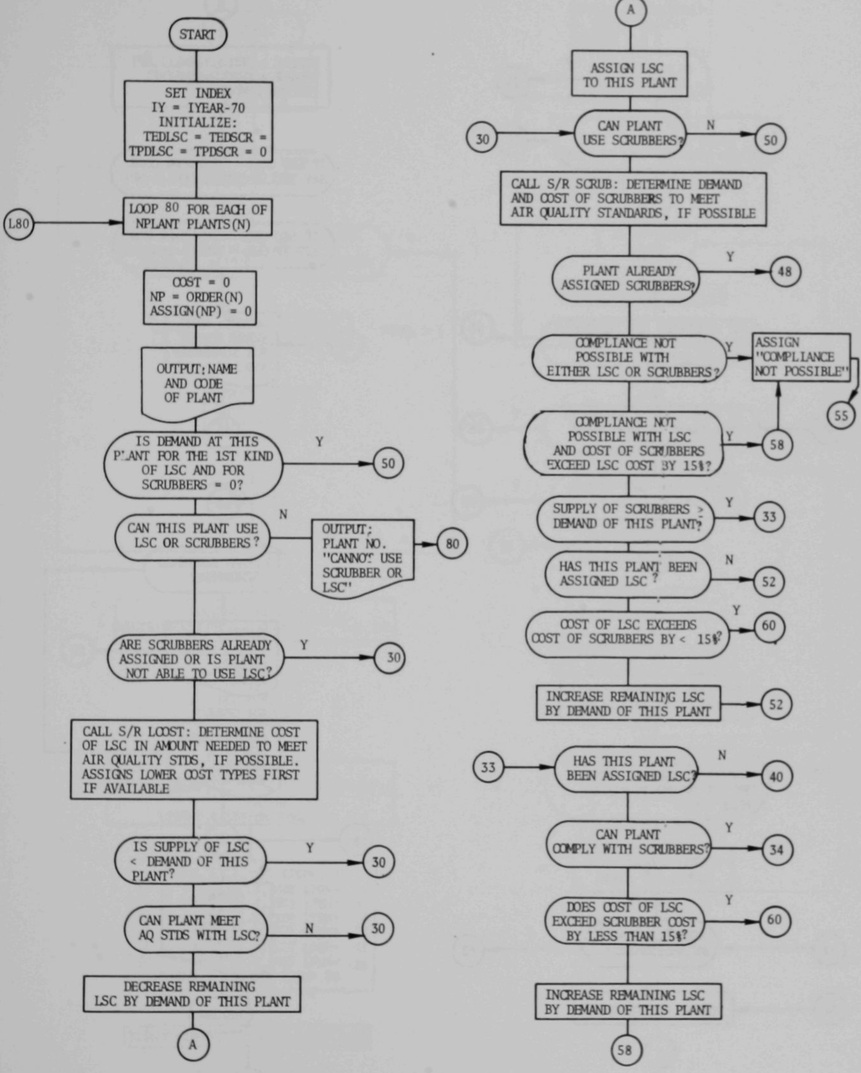
S/R SUBPRI/ PRI/



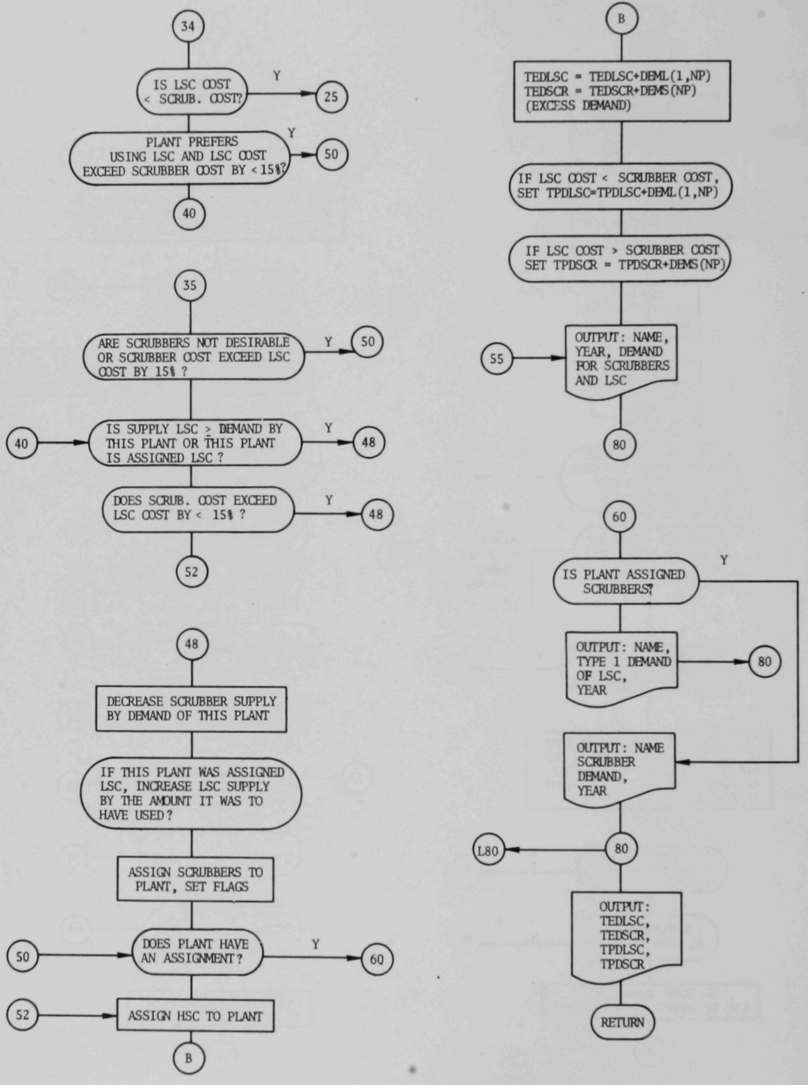
S/R DEMAND /LSCOAL,PLANT/



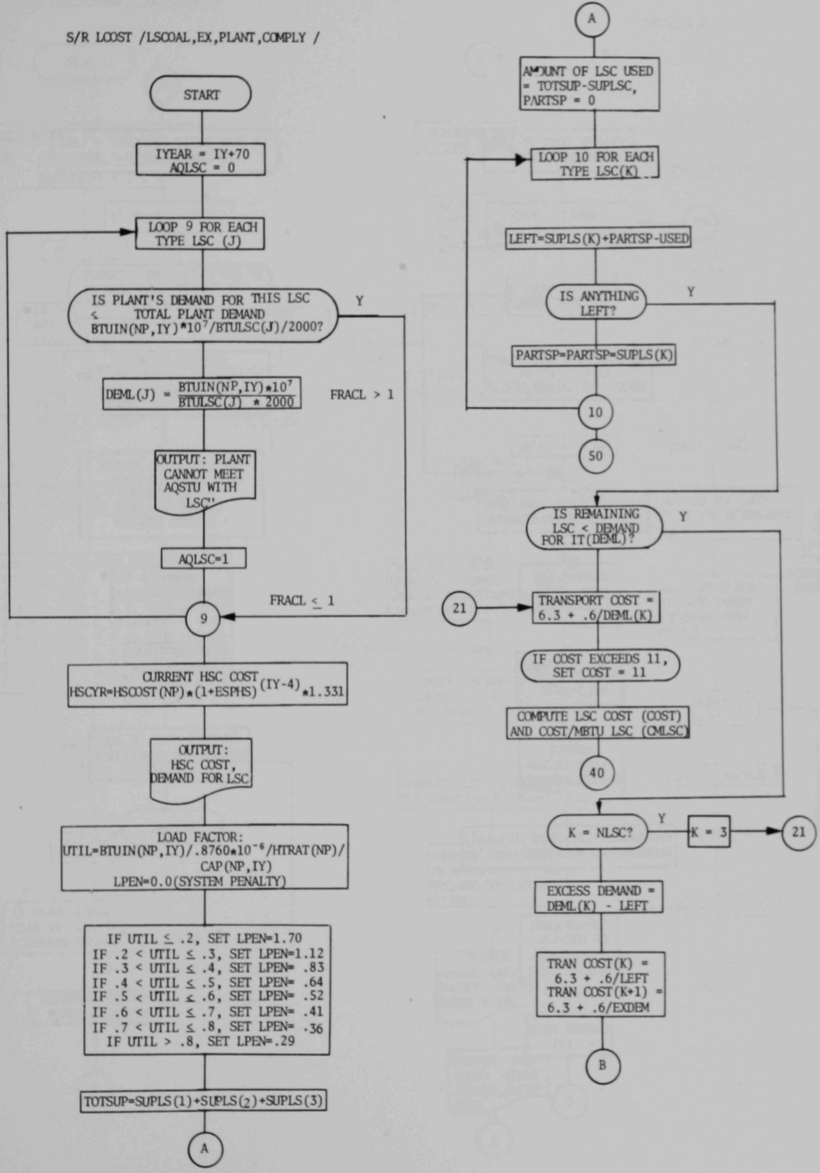
S/R ASSIGN /LOCATE,PRI/



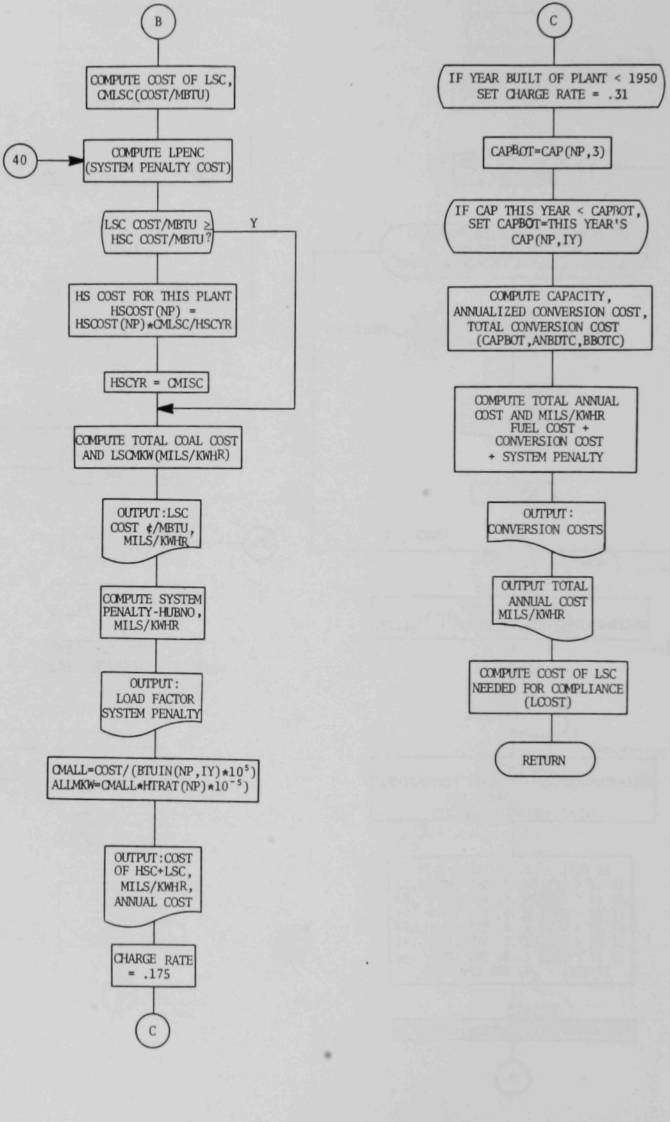
S/R ASSIGN


34
IS LSC COST < SCRUB. COST?
Y
25
PLANT PREFERS USING LSC AND LSC COST EXCEED SCRUBBER COST BY < 15%?
Y
50
40
35
ARE SCRUBBERS NOT DESIRABLE OR SCRUBBER COST EXCEED LSC COST BY 15% ?
Y
50
40
IS SUPPLY LSC ≥ DEMAND BY THIS PLANT OR THIS PLANT IS ASSIGNED LSC ?
Y
48
DOES SCRUB. COST EXCEED LSC COST BY < 15% ?
Y
48
52
48
DECREASE SCRUBBER SUPPLY BY DEMAND OF THIS PLANT
IF THIS PLANT WAS ASSIGNED LSC, INCREASE LSC SUPPLY BY THE AMOUNT IT WAS TO HAVE USED?
ASSIGN SCRUBBERS TO PLANT, SET FLAGS
50
DOES PLANT HAVE AN ASSIGNMENT?
Y
60
52
ASSIGN HSC TO PLANT
B
B
TEDLSC = TEDLSC+DEML(1,NP)
TEDSCR = TEDSCR+DEMS(NP)
(EXCESS DEMAND)
IF LSC COST < SCRUBBER COST, SET TPDLSC=TPDLSC+DEML(1,NP)
IF LSC COST > SCRUBBER COST SET TPDSCR = TPDSCR+DEMS(NP)
55
OUTPUT: NAME, YEAR, DEMAND FOR SCRUBBERS AND LSC
80
60
IS PLANT ASSIGNED SCRUBBERS?
Y
OUTPUT: NAME, TYPE 1 DEMAND OF LSC, YEAR
80
OUTPUT: NAME SCRUBBER DEMAND, YEAR
L80
80
OUTPUT: TEDLSC, TEDSCR, TPDLSC, TPDSCR
RETURN

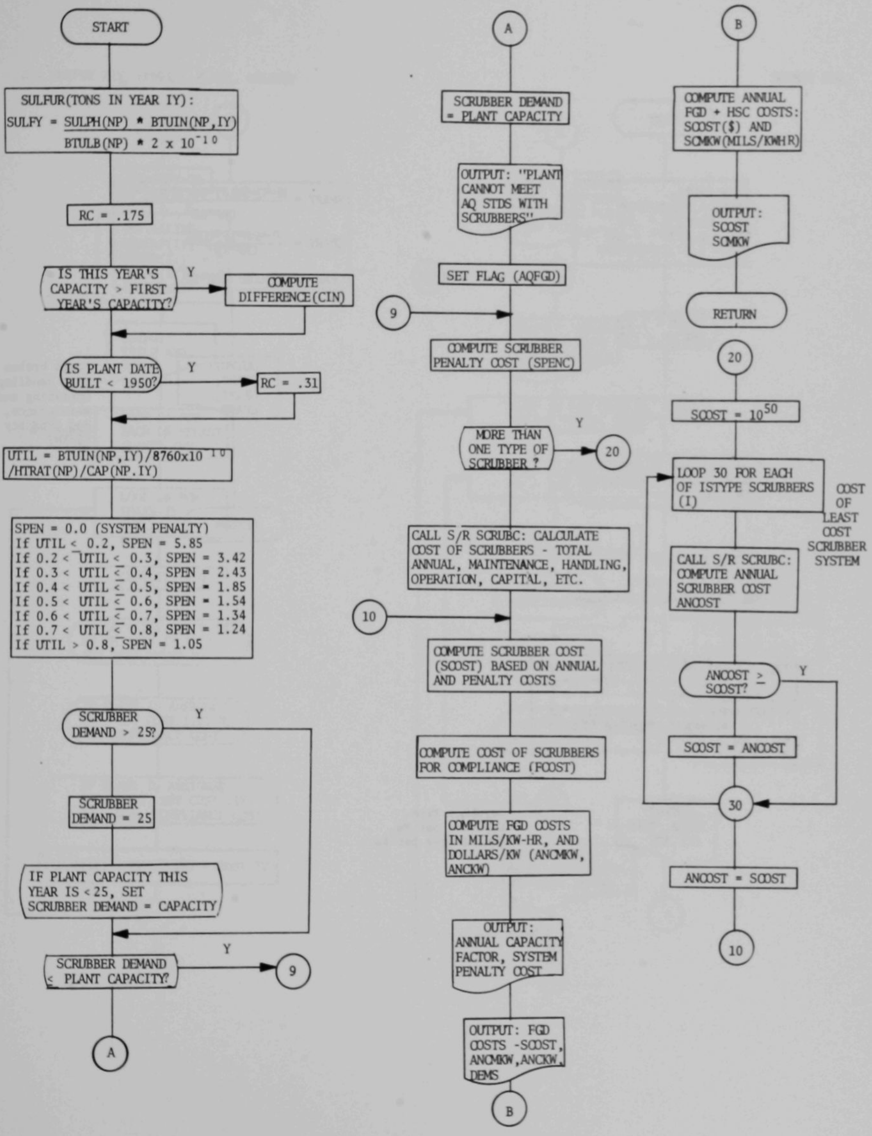
S/R LCOST /LSCOAL,EX,PLANT,COMPLY /



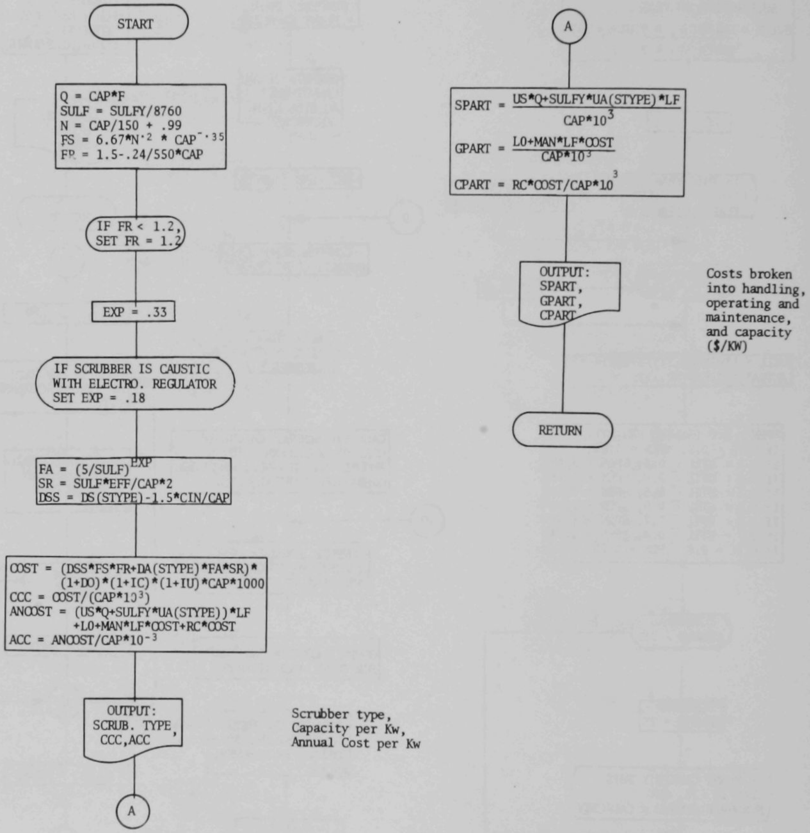
S/R LCOST


B
COMPUTE COST OF LSC, CMLSC(COST/MBTU)
40
COMPUTE LPENC (SYSTEM PENALTY COST)
LSC COST/MBTU ≥ HSC COST/MBTU?
Y
HS COST FOR THIS PLANT HSCOST(NP) = HSCOST(NP)*CMLSC/HSCYR
HSCYR = CMISC
COMPUTE TOTAL COAL COST AND LSCMKW(MILS/KWHR)
OUTPUT:LSC COST ¢/MBTU, MILS/KWHR
COMPUTE SYSTEM PENALTY-HUBNO, MILS/KWHR
OUTPUT: LOAD FACTOR SYSTEM PENALTY
CMALL=COST/(BTUIN(NP,IY)*10^5)
ALLMKW=CMALL*HTRAT(NP)*10^-5)
OUTPUT:COST OF HSC+LSC, MILS/KWHR, ANNUAL COST
CHARGE RATE = .175
C
C
IF YEAR BUILT OF PLANT < 1950 SET CHARGE RATE = .31
CAPBOT=CAP(NP,3)
IF CAP THIS YEAR < CAPBOT, SET CAPBOT=THIS YEAR'S CAP(NP,IY)
COMPUTE CAPACITY, ANNUALIZED CONVERSION COST, TOTAL CONVERSION COST (CAPBOT,ANBOTC,BBOTC)
COMPUTE TOTAL ANNUAL COST AND MILS/KWHR FUEL COST + CONVERSION COST + SYSTEM PENALTY
OUTPUT: CONVERSION COSTS
OUTPUT TOTAL ANNUAL COST MILS/KWHR
COMPUTE COST OF LSC NEEDED FOR COMPLIANCE (LCOST)
RETURN

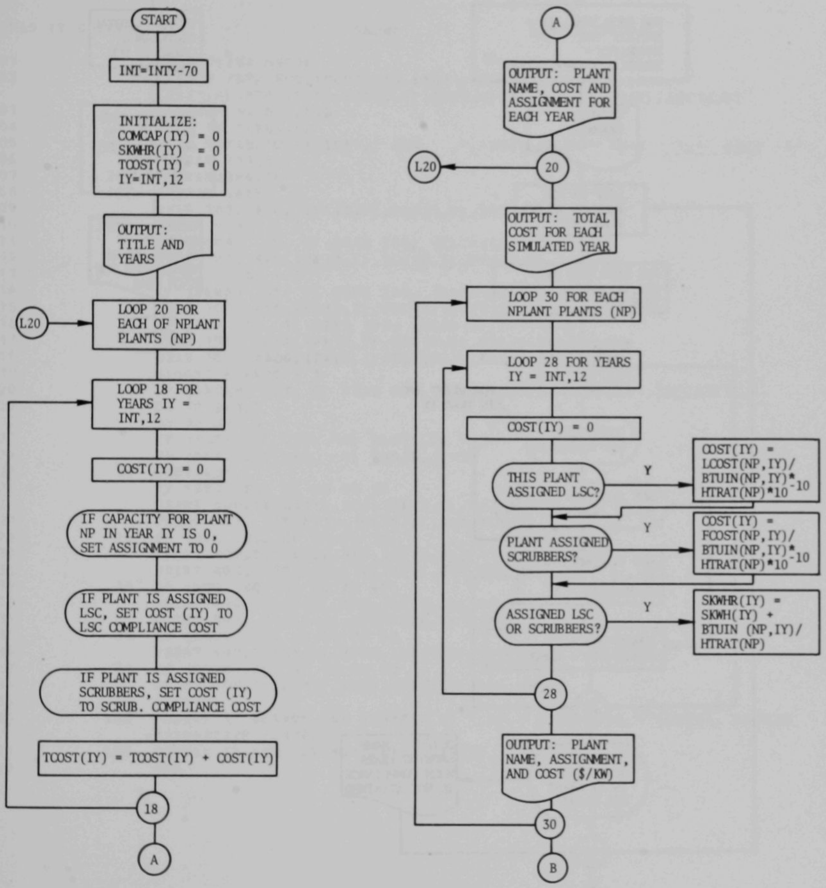
S/R SCRUB /EX,SCRUBB,PLANT,COMPLY/



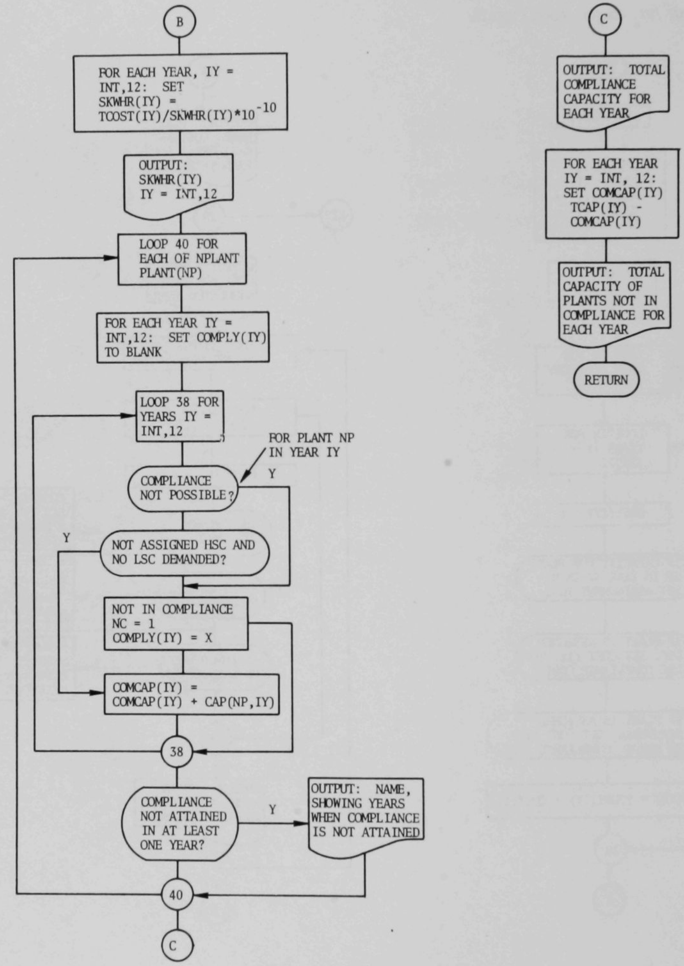
S/R SCRUBC


START
Q = CAP*F
SULF = SULFY/8760
N = CAP/150 + .99
FS = 6.67*N^.2 * CAP^-.35
FR = 1.5-.24/550*CAP
IF FR < 1.2, SET FR = 1.2
EXP = .33
IF SCRUBBER IS CAUSTIC WITH ELECTRO. REGULATOR SET EXP = .18
FA = (5/SULF)^EXP
SR = SULF*EFF/CAP*2
DSS = DS(STYPE)-1.5*CIN/CAP
COST = (DSS*FS*FR+DA(STYPE)*FA*SR)*(1+DO)*(1+IC)*(1+IU)*CAP*1000
CCC = COST/(CAP*10^3)
ANCOST = (US*Q+SULFY*UA(STYPE))*LF +LO+MAN*LF*COST+RC*COST
ACC = ANCOST/CAP*10^-3
OUTPUT: SCRUB. TYPE, CCC,ACC
Scrubber type, Capacity per Kw, Annual Cost per Kw
A
A
SPART = (US*Q+SULFY*UA(STYPE)*LF) / CAP*10^3
GPART = (LO+MAN*LF*COST) / CAP*10^3
CPART = RC*COST/CAP*10^3
OUTPUT: SPART, GPART, CPART
Costs broken into handling, operating and maintenance, and capacity ($/KW)
RETURN

S/R OUTPUT /EX, COMPLY, PLANT, LOCATE/



S/R OUTPUT


B
FOR EACH YEAR, IY = INT,12: SET SKWHR(IY) = TCOST(IY)/SKWHR(IY)*10^-10
OUTPUT: SKWHR(IY) IY = INT,12
LOOP 40 FOR EACH OF NPLANT PLANT(NP)
FOR EACH YEAR IY = INT,12: SET COMPLY(IY) TO BLANK
LOOP 38 FOR YEARS IY = INT,12
FOR PLANT NP IN YEAR IY
COMPLIANCE NOT POSSIBLE?
Y
NOT ASSIGNED HSC AND NO LSC DEMANDED?
Y
NOT IN COMPLIANCE NC = 1 COMPLY(IY) = X
COMCAP(IY) = COMCAP(IY) + CAP(NP,IY)
38
COMPLIANCE NOT ATTAINED IN AT LEAST ONE YEAR?
Y
OUTPUT: NAME, SHOWING YEARS WHEN COMPLIANCE IS NOT ATTAINED
40
C
C
OUTPUT: TOTAL COMPLIANCE CAPACITY FOR EACH YEAR
FOR EACH YEAR IY = INT, 12: SET COMCAP(IY) TCAP(IY) - COMCAP(IY)
OUTPUT: TOTAL CAPACITY OF PLANTS NOT IN COMPLIANCE FOR EACH YEAR
RETURN

I.F. PROGRAM LISTINGS

```
FORTRAN IV G LEVEL  21                    MAIN                 DATE = 75070

              REAL TCAP(12)
              CALL GROUP
              CALL RSUP (INTY)
              CALL RPLANT (NPLANT,TCAP)
              CALL SIMU (NPLANT,INTY)
              CALL OUTPUT (INTY,TCAP)
              STOP
              END

FORTRAN IV G LEVEL  21                    GROUP                DATE = 75070

              SUBROUTINE GROUP
              COMMON /GP/ NCG,NCGM1,NAG,NAGM1,NMG,NURG,NAQG,NAQGM1,
             - PA(5,4),PLC (5,4),PSB(5,4),CLIM(4),ALIM(4),MLIM(4),AQC(3,8)
              INTEGER PA,PLC,PSB
              REAL *8 TITLE(5)
              DATA TITLE/'CAPACITY',' AGE    ','MINE MO ','  U-R   ','  AQCR  '/
          100 FORMAT (13I6)
          200 FORMAT(3F6.0)
          300 FORMAT (8A4)
              READ 100, NCG, (PA(1,I),PLC(1,I),PSB(1,I),I=1,4)
              NCGM1 = NCG - 1
              IF (NCGM1 .GT. 0) READ 200, (CLIM(I),I=1,NCGM1)
              READ 100, NAG,(PA(2,I),PLC(2,I),PSB(2,I),I=1,4)
              NAGM1 = NAG - 1
              IF (NAGM1 .GT. 0) READ 200, (ALIM(I),I=1,NAGM1)
              READ 100, NMG,(PA(3,I),PLC(3,I),PSB(3,I),I=1,4)
              IF (NMG .GT. 1) READ 100, (MLIM(I),I=1,NMG)
              READ 100, NURG,(PA(4,I),PLC(4,I),PSB(4,I),I=1,4)
              READ 100, NAQG,(PA(5,I),PLC(5,I),PSB(5,I),I=1,4)
              NAQGM1 = NAQG - 1
              IF (NAQGM1 .GT. 0) READ 300, ((AQC(I,J),J=1,8),I=1,NAQGM1)
              DO 10 I=1,5
              DO 10 J=1,4
              IF (PLC(I,J) .EQ. -1) PLC(I,J) = 2
              IF (PSB(I,J) .EQ. -1) PSB(I,J)=2
           10 CONTINUE
              IF (NCG .EQ. 0) GO TO 20
              PRINT 400,TITLE(1),NCG,(PA(1,I),I=1,NCG)
              PRINT 401, TITLE(1),(CLIM(I),I=1,NCGM1)
           20 IF (NAG .EQ. 0) GO TO 30
              PRINT 400,TITLE(2),NAG,(PA(2,I),I=1,NAG)
              PRINT 401, TITLE(2),(ALIM(I),I=1,NAGM1)
           30 IF (NMG .EQ. 0) GO TO 40
              PRINT 400,TITLE(3),NMG,(PA(3,I),I=1,NMG)
              PRINT 401, TITLE(3),(MLIM(I),I=1,NMG)
           40 IF (NURG .EQ. 0) GO TO 50
              PRINT 400,TITLE(4),NURG,(PA(4,I),I=1,NURG)
           50 IF (NAQG .EQ. 0) GO TO 60
              PRINT 400,TITLE(5),NAQG,(PA(5,I),I=1,NAQG)
           60 RETURN
          400 FORMAT (' PLANTS ARE GROUPED BY ',A8,' WITH ',I4,' GROUPS, HAVING
             -PRIORITIES ',4I6)
          401 FORMAT (' AND HAVING ',A8,' LIMITS ',4F12.2)
              END
```

```
          SUBROUTINE RSUP (INTY)
          COMMON /LSCOAL/ NLSC,SUPLS(3),CMINE(3),ESFACM(3),CTRANS(3),
         - ESFACT(3),BTULSC(3),SULLSC(3),ISRT(3),SPER(3),IYRLS(3),
         - SUPLSI(3),SUPLSY(3,10)
          COMMON /SCRUBB/ ISRTS,SPERS,IYRS,SUPSI,ESFSC,ISTYPE,STYPE(5)
         - ,SUPSC(10)
          COMMON /STRAT/ NSTRAT,SYR(20),STAND(20),KIND(20),STA(20),SAQ(20),
         - SCOUN(20),SUR(20),SCMIN(20),SCMAX(20),SAMIN(20),SAMAX(20),AQS(20)
          INTEGER STYPE,SYR,STA,SAQ
      100 FORMAT (12F6.0)
      200 FORMAT (I6,F6.0,4X,I2,2F6.0,5I6)
      300 FORMAT (4X,I2,F6.0,3I6,3X,A3,5X,A1,4F6.0)
      400 FORMAT (12(3X,A3))
          DO 10 K=1,3
          READ 100, CMINE(K),ESFACM(K),CTRANS(K),ESFACT(K),BTULSC(K),
         - SULLSC(K)
          IF (CMINE(K) .EQ. 0.) GO TO 20
          SULLSC(K) = SULLSC(K) / 100.
          ESFACM(K) = ESFACM(K) / 100.
          ESFACT(K) = ESFACT(K) / 100.
          READ 200, ISRT(K),SPER(K),IYRLS(K),SUPLSI(K)
          SPER(K) = SPER(K) / 100.
          IF (ISRT(K) .EQ. 1) READ 100, (SUPLSY(K,I),I=1,10)
       10 CONTINUE
          K = 4
       20 NLSC = K - 1
          READ 200, ISRTS, SPERS, IYRS, SUPSI, ESFSC,(STYPE(I),I=1,5)
          ESFSC = ESFSC / 100.
          SPERS = SPERS / 100.
          ISTYPE = 1
          DO 30 I=2,5
          IF (STYPE(I) .NE. 0) ISTYPE = ISTYPE + 1
       30 CONTINUE
          IF (ISRTS .EQ. 1) READ 100, (SUPSC(I),I=1,10)
          READ 300, NSTRAT
          NAQ = 0
          IF (NSTRAT .GT. 20) GO TO 60
          PRINT 498
      498 FORMAT (/'  # YEAR   STANDARD TYPE STATE AQCR COUNTY U/R  CAPACITY
         - MW   YEAR BUILT')
          DO 40 I=1,NSTRAT
          READ 300, SYR(I),STAND(I),KIND(I),STA(I),SAQ(I),SCOUN(I),SUR(I),
         - SCMIN(I),SCMAX(I),SAMIN(I),SAMAX(I)
          PRINT 499, I,SYR(I),STAND(I),KIND(I),STA(I),SAQ(I),SCOUN(I),SUR(I)
         -,SCMIN(I),SCMAX(I),SAMIN(I),SAMAX(I)
      499 FORMAT (1X,I2,2X,I2,2X,E10.4,2X,I1,3X,I3,2X,I3,4X,A3,3X,A1,2X,4F6.
         -0)
          IF (SAQ(I) .EQ. 0) GO TO 40
          NAQI = NAQ + 1
          NAQ = NAQ + SAQ(I)
          READ 400, (AQS(J),J=NAQI,NAQ)
          PRINT 497, (AQS(J), J= NAQI,NAQ)
      497 FORMAT (' AQCR LIST', 10(3X,A3))
       40 CONTINUE
          INTY = SYR(1)
          RETURN
       60 PRINT 500
          RETURN
      500 FORMAT (/// '   TOO MANY STRATEGY CARDS   **********************')
          END
```

```
              SUBROUTINE BPLANT (NP, TCAP)
              COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
             - BTULB(300)
              COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
             - ECRAT(300),AGE(300),ESFHS,WETFR(300)
              COMMON /LOCATE/ NAME(3,300),CODE(3,300),STATE(300),AQCR(300),
             - COUNTY(300),MINEMO(300),URBAN(300)
              INTEGER CODE,STATE,DAT(2),BCODE(10),DATE(2,10),DCOAL(10),DOIL(10),DGAS(10)
             - DGAS(10),WET(10),ADD,EXIST,COAL,OIL,GAS,BLANK,C1,C2,C3
              REAL BCAP(10),BUTIL(10)
              REAL TSBTU(12),TCAP(12),CAPACY(300)
              DATA   BLANK/ '    '/
         100  FORMAT(4A4,I2,1X,I4,I2,A1,A3,A3,2I2,2I1,F6.1,F8.1,F5.1,F8.5,F5.1,
             -3I3,I1)
         200  FORMAT (20X,I3,9X,I2,I2,2X,F6.1,8X,F5.1,8X,F5.1,3A3,I1)
         300  FORMAT (12X,A4,I2,1X,I4,1X,2F6.0,I6,F6.3,F8.0)
              NPLANT = 0
              NP = 1
              ESFHS = .04
           1  READ (8,100) (NAME(I,NP),I=1,3),(CODE(I,NP),I=1,3),STATE(NP),
             - URBAN(NP),AQCR(NP),COUNTY(NP),DAT,EXIST,MINEMO(NP),CAPACY(NP),
             - OUTPUT, UTIL,BTUI ,SULPH(NP),COAL,OIL,GAS,ADD
              IF (CODE(1,NP) .EQ. BLANK) GO TO 30
              IF (ADD .EQ. 0) GO TO 8
              DO 10 J=1,ADD
          10  READ (8,200) BCODE(J),(DATE(I,J),I=1,2),BCAP(J),BUTIL(J),
             1 HTR      ,DCOAL(J),DOIL(J),DGAS(J),WET(J)
              DO 7 J=1,ADD
              IF (BCODE(J) .EQ. ((BCODE(J)/100)*100) .AND. ADD .LE. 1) GOTO 8
           7  CONTINUE
              IF (EXIST .NE. 1) GO TO 8
              DO 5 I=1,ADD
              IF (DATE(2,I) .LE. 70) GO TO 12
           5  CONTINUE
           8  ADD = ADD + 1
              BCODE(ADD) = CODE(3,NP)
              BCAP(ADD) = CAPACY(NP)
              BUTIL(ADD) = UTIL
              WET(J) = 0
              DCOAL(ADD) = COAL
              DOIL(ADD) = OIL
              DGAS(ADD) = GAS
              IF (COAL .EQ. 0) DCOAL(ADD) = BLANK
              IF (OIL .EQ. 0) DOIL(ADD) = BLANK
              IF (GAS .EQ. 0) DGAS(ADD) = BLANK
              DO 11 I=1,2
          11  DATE(I,ADD) = DAT(I)
              IF (DAT(2) .EQ. 0) DATE(2,ADD) = 60
          12  CONTINUE
              SULPH(NP) = SULPH(NP) / 100.
              PUTIL = 75.
              IF (OUTPUT .NE. 0) PUTIL = OUTPUT / (CAPACY(NP) * .0876)
              IF (OUTPUT .EQ. 0) HTRAT(NP) = 9000.
              IF (OUTPUT .NE. 0) HTRAT(NP) = BTUI / OUTPUT * 1.E7
              CALL PANAL(NP,ADD,EXIST,BTUI,COAL,BCODE,BCAP,BUTIL,DATE,DCOAL,
```

```
FORTRAN IV G LEVEL  21                RPLANT        DATE = 75070        08/28/03

                - DOIL,DGAS,WET,PUTIL)
                  NP = NP + 1
                  GO TO 1
               30 PRINT 201, NPLANT
              201 FORMAT (' NUMBER OF PLANTS IN SYSTEM IN FIRST YEAR ',I3)
                  DO 31 IY=1,12
                  TSBTU(IY) = 0.
              31  TCAP(IY) = 0.
                  DO 35 N=1,NPLANT
              33  READ(8,300) C1,C2,C3,HSCOST(N),BTULB(N),MILES(N),ECRAT(N),FLGRT(N)
                  IF (HSCOST(N) .EQ. 0.) HSCOST(N) = 40.
                  IF (BTULB(N) .EQ. 0.) BTULB(N) = 11000.
                  FLGRT(N) = FLGRT(N) / CAPACY(N)
                  IF (FLGRT(N) .EQ. 0) FLGRT(N) = 2000.
                  IF (FLGRT(N) .GT. 20000. ) FLGRT(N) = FLGRT(N) / 10.
                  DO 35 IY=1,12
                  TSBTU(IY) = TSBTU(IY) + BTUIN(N,IY)
                  TCAP(IY) = TCAP(IY) + CAP(N,IY)
              35  CONTINUE
                  PRINT 701
              701 FORMAT (' TOTAL COAL FIRED CAPACITY    ( MW)')
                  PRINT 700, TCAP
                  PRINT 702
              702 FORMAT (' TOTAL COAL DEMAND  ( 10 TO 13 BTU)')
                  PRINT 700, TSBTU
              700 FORMAT (6F20.2)
                  NP = NP - 1
                  RETURN
                  END
```

```
      SUBROUTINE PANAL(NP,ADD,EXIST,BTUI,COAL.BCODE,BCAP,BUTIL,DATE,
     - DCOAL,DOIL,DGAS,WET,PUTIL)
      COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
     - BTULB(300)
      COMMON /LOCATE/ NAME(3,300),CODE(3,300),STATE(300),AQCR(300),
     - COUNTY(300),MINEMO(300),URBAN(300)
      COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
     - ECRAT(300),AGE(300),ESHFC,WETFR(300)
      INTEGER CODE,STATE,DAT(2),BCODE(10),DATE(2,10),DCOAL(10),DOIL(10),D
     - DGAS(10),WET(10),ADD,EXIST,COAL,OIL,GAS
      REAL BCAP(10),BUTIL(10)
      INTEGER PFLAG
      WETFR(NP) = 0.
      BSUM = 0.0
      BBSUM = 0.0
      DO 15 LL = 1, ADD
      IF ( DATE(2, LL) .GE. 71) GO TO 15
      BBSUM = BBSUM + BCAP(LL)
      BSUM = BSUM + BCAP(LL)*BUTIL(LL)/100.
   15 CONTINUE
      BERROR = BSUM*8760.E3 - BTUI/HTRAT(NP)*1.E13
      DO 16 LL = 1, ADD
      IF (DATE(2, LL) .GE. 71) GO TO 16
      BUTIL(LL) = BUTIL(LL) - BERROR/(BBSUM*8760.E1)
      BUTIL(LL) = ABS(BUTIL(LL))
   16 CONTINUE
      IF (EXIST .EQ. 0) GO TO 20
      BTUI  = BTUI  * COAL / 100.
      IF (BTUI  .LT. .02) GO TO 70
      IF (COAL .LT. 2) GO TO 70
   20 CALL PROJ(ADD,BCODE,BCAP,BUTIL,DATE,DCOAL,DOIL,DGAS,NP,PUTIL,BTUI)
      IF (NP .EQ. NPLANT ) GO TO 50
      NPLANT = NP
      WCAP = 0.
      DO 30 J=1,ADD
      IF (DATE(2,J) .GT. 73) GO TO 30
      IF (WET(J) .EQ. 1) WCAP = WCAP + BCAP(J)
   30 CONTINUE
      CALL PRIOR(CAP(NP,1),AGE(NP),MINEMO(NP),URBAN(NP),AQCR(NP),NP,
     - PFLAG)
   45 IF (SULPH(NP) .EQ. 0.) SULPH(NP) = .035
      IF (CAP(NP,3) .EQ. 0) RETURN
      WETFR(NP) = WCAP / CAP(NP,3)
   50 RETURN
   70 DO 75 J=1,ADD
      IF (DATE(2,J) .GT. 70 .AND. BCAP(J) .GT. 0) GO TO 20
   75 CONTINUE
      NP = NP - 1
      RETURN
      END
```

```
                SUBROUTINE PROJ(NB,BCODE,BCAP,BUTIL,DATE,DCOAL,DOIL,DGAS,NP,PUTIL,
               - BTUI)
                DIMENSION BCODE(10),BCAP(10),BUTIL(10),ECAP(10),DCOAL(10),DOIL(10)
               - ,DGAS(10)
                INTEGER DATE(2,10)
                COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
               - BTULB(300)
                COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
               - ECRAT(300),AGE(300)
                DATA BLANK /'    '/
                EAGE = 0.
                BAGE = 0.
                KOG = 0
                DBTU = 0.
                DO 150 IY=1,12
                CAP(NP,IY) = 0.
                DO 10 J=1,NB
             10 ECAP(J) = 0.
                DO 30 J=1,NB
                IF (DCOAL(J) .NE. BLANK) GO TO 13
                IF (DOIL(J) .NE. BLANK .OR. DGAS(J) .NE. BLANK) GO TO 30
                IF (BUTIL(J) .NE. 0 .AND. BUTIL(J) .LT. 2.0) GO TO 30
             13 IF (BCAP(J) .GT. 0) GO TO 15
                 IF (DATE(2,J) .GT. (70+IY)) GO TO 30
                DO 11 I=1,NB
                IF (BCODE(J) .EQ. BCODE(I) .AND. I .NE. J) GO TO 12
             11 CONTINUE
                I = 1
             12 IF (DATE(2,J) .LT. (70+IY)) GO TO 14
                MPART = DATE(1,J)
                IF (MPART .EQ. 0) MPART = 7
             16 ECAP(I) = ECAP(I) + (13.-MPART)/12. * BCAP(J)
                IF ((DOIL(I) .EQ. BLANK .AND. DGAS(I) .EQ. BLANK) .OR. DBTU .EQ. 0
               - ) GO TO 17
                BTU = -BCAP(J) * BUTIL(I)
                BTUJ = 0.
                DO 18 IJ=1,NB
                IF (IJ .EQ. I .OR. IJ .EQ. J) GO TO 18
                IF ((DOIL(IJ).EQ. BLANK.AND.DGAS(IJ).EQ.BLANK) .OR.DCOAL(IJ).EQ.
               -BLANK) GO TO 18
                BTUJ = BTUJ + BCAP(IJ) * BUTIL(IJ)
             18 CONTINUE
                KOG = 2
                DBTUT = DBTU
                DBTU = DBTU * (1.-BTU/(BTU+BTUJ)*(-BCAP(J))/BCAP(I))
                DBTUT =((MPART-1)*DBTUT + (13-MPART)*DBTU)/12.
             17 IF (ECAP(I) .GE. 0 .OR.J.LE. I) GO TO 30
                EXCAP = ECAP(I)
                ECAP(I) = 0.
                I = I + 1
                ECAP(I) = ECAP(I) + EXCAP
                GO TO 17
             14 ECAP(I) = ECAP(I) + BCAP(J)
                GO TO 17
             15 IF (DATE(2,J) - (70+IY)) 20,21,25
```

```
   20  ECAP(J) = BCAP(J) + ECAP(J)
       IF (BUTIL(J) .EQ. 0.) BUTIL(J) = 50.
       IF(IY.EQ.1.AND.(DOIL(J).NE.BLANK.OR.DGAS(J).NE.BLANK))KOG=1
       GO TO 30
   21  MPART = DATE(1,J)
       IF (MPART .EQ. 0) MPART = 7
       ECAP(J) = ECAP(J) + (13.-MPART)/12.*BCAP(J)
       BUTIL(J) = 75
       GO TO 30
   25  ECAP(J) = 0.
   30  CONTINUE
       BTU = 0.
       DO 40 J=1,NB
       CAP(NP,IY) = CAP(NP,IY) + ECAP(J)
       IF (IY .EQ. 1) BAGE = BAGE + ECAP(J) * DATE(2,J)
       IF (IY .EQ. 12) EAGE = EAGE + ECAP(J) * DATE(2,J)
       IF (ECAP(J) .NE. 0 .AND. DATE(2,J) .GT. 70) GO TO 43
       BTU = BTU + ECAP(J) * BUTIL(J) *  HTRAT(NP)
       GO TO 40
   43  BTU = BTU + ECAP(J) * BUTIL(J) * 9000.
   40  CONTINUE
       IF (IY .NE. 1) GO TO 55
       IF (BTU .EQ. 0) GO TO 56
       BAGE = BAGE / CAP(NP,1)
   55  IF (IY .EQ.12  .AND. CAP(NP,12).NE. 0) EAGE = EAGE / CAP(NP,12)
   56  BTUIN(NP,IY) = BTU * 8760.E-12
       IF (KOG .EQ. 0) GO TO 150
       IF (IY .EQ. 1) DBTU = BTUIN(NP,1) - BTUI
       IF (KOG .EQ. 2) GO TO 70
       IF (DBTU .LT. 0) DBTU = 0.
       BTUIN(NP,IY) = BTUIN(NP,IY) - DBTU
       IF (BTUIN(NP,IY) .LT. 0.) BTUIN(NP,IY) = 0.
  150  CONTINUE
       IF (BAGE .EQ. 0. .AND. EAGE .EQ. 0.) GO TO 60
       AGE(NP) = (BAGE*CAP(NP,1) + EAGE*CAP(NP,12)) / (CAP(NP,1)+CAP(NP,12))
     -2))
       IF (BAGE .NE. 0) GO TO 45
       SULPH(NP) = .035
       HTRAT(NP) = 9000.
   45  DO 50 I=7,12
       IF (CAP(NP,I) .NE. 0) GO TO 180
   50  CONTINUE
   60  NP = NP - 1
  180  RETURN
   70  KOG = 1
       BTUIN(NP,IY) = BTUIN(NP,IY) - DBTUT
       GO TO 150
       END
```

```
FORTRAN IV G LEVEL  21                  PRIOR                DATE = 75070          08/28/03

                 SUBROUTINE PRIOR (CAP,AGE,MINEMO,URBAN,AQCR,NP,PFLAG)
                 COMMON /GP/ NCG,NCGM1,NAG,NAGM1,NMG,NURG,NAQG,NAQGM1,
                - PA(5,4),PLC  (5,4),PSB(5,4),CLIM(4),ALIM(4),MLIM(4),AQC(3,8)
                 DATA U /'U'/
                 COMMON /PRI/ ORDER(300),NPRIOR,MAXP,MINP,PRIOR(300),PCOUNT(100),
                - LSCF(300),SCRF(300)
                 INTEGER PRIOR,SCRF, PFLAG, PA, PLC, PSB, PCOUNT
                 IF (NP .NE. 1) GO TO 4
                 NPRIOR = 0
                 DO 3 I=1,100
               3 PCOUNT(I) = 0
               4 LSCF(NP) = 0
                 SCRF(NP) = 0
                 PRIOR(NP) = 0
                 J = 1
               5 GO TO (10,20,30,40,50,70),J
              10 IF (NCG .LE. 1) GO TO 15
                 DO 12 I=1,NCGM1
                 IF (CAP .LT. CLIM(I)) GO TO 13
              12 CONTINUE
                 I = NCG
              13 PRIOR(NP) = PRIOR(NP) + PA(J,I)
                 IF (PLC (J,I) .GT. LSCF(NP)) LSCF(NP) = PLC (J,I)
                 IF (PSB(J,I) .GT. SCRF(NP)) SCRF(NP) = PSB(J,I)
              15 J = J + 1
                 GO TO 5
              20 IF (NAG .LE. 1) GO TO 15
                 DO 22 I=1,NAGM1
                 IF (AGE .LT. ALIM(I)) GO TO 13
              22 CONTINUE
                 I = NAG
                 GO TO 13
              30 IF (NMG .LE. 1) GO TO 15
                 DO 32 I=1,NMG
                 IF (MINEMO .LE. MLIM(I)) GO TO 13
              32 CONTINUE
                 I = NMG
                 GO TO 13
              40 IF (NURG .LE. 1) GO TO 15
                 I = 1
                 IF (URBAN .EQ. U) GO TO 13
                 I = 2
                 GO TO 13
              50 IF (NAQG .LE. 1) GO  TO 15
                 DO 52 I=1,NAQGM1
                 DO 52 K=1,8
                 IF (AQCR .EQ. AQC(I,K)) GO TO 13
              52 CONTINUE
                 I = NAQG
                 GO TO 13
              70 I = PRIOR(NP) + 1
                 IF (I .GT. NPRIOR ) NPRIOR = I
                 MAXP = NPRIOR
                 IF (I .GT. 100) GO TO 80
                 IF (I .LE. 0) GO TO 90
```

```
FORTRAN IV G LEVEL  21                  PRIOR                DATE = 75070          08/28/03

                 PCOUNT(I) = PCOUNT(I) + 1
                 RETURN
              80 IF (PFLAG .LE. 1) PFLAG = 1
                 IF (PFLAG .EQ. 2) PFLAG = 3
                 RETURN
              90 IF (PFLAG .LE. 1) PFLAG = PFLAG + 2
                 RETURN
                 END
```

```
0001                SUBROUTINE SIMU (NPLANT,INTY)
0002                COMMON /LSCOAL/ NLSC,SUPLS(3),CMINE(3),ESFACM(3),CTRANS(3),
                   - ESFACT(3),BTULSC(3),SULLSC(3),ISRT(3),SPER(3),IYRLS(3),
                   - SUPLSI(3),SUPLSY(3,10)
0003                COMMON /SCRUBB/ ISRTS,SPERS,IYRS,SUPSI,ESFSC,ISTYPE,STYPE(5)
                   - ,SUPSC(10)
0004                COMMON /COMPLY/ TCOAL(12),TSCR(12),EXCOAL(12),EXSCR(12),ASSIG(300
                   -,12),LCOST(300,12),FCOST(300,12)
0005                INTEGER ASSIGN
0006                REAL DEML(3,300),DEMS(300), AQDIF(300),LCOST
0007                DO 3 I=1,3
0008              3 SUPLS(I) = 0.
0009                DO 200 IYEAR = INTY,82
0010                IY = IYEAR - 70
0011                DO 5 N=1,NPLANT
0012                LCOST(N,IY) = 0.
0013                FCOST(N,IY) = 0.
0014                DO 4 I=1,3
0015              4 DEML(I,N) = 0.
0016              5 DEMS(N) = 0.
0017                TCOAL(IY-1) = SUPLS(1) + SUPLS(2) + SUPLS(3)
0018                DO 70 K=1,NLSC
0019                IF (IYEAR - IYRLS(K)) 60,50,10
0020             10 TSUPL = TSUPL - SUPLS(K)
0021                IF (ISRT(K) - 2) 20,30,40
0022             20 I = IYEAR - IYRLS(K)
0023                SUPLS (K) = SUPLSY(K,I)
0024                GO TO 70
0025             30 I = IYEAR - IYRLS(K)
0026                SUPLS(K) = SUPLSI(K) * (1.+SPER(K))**I
0027                GO TO 70
0028             40 IF (ISRT(K) .GT. 3) GO TO 70
0029                IF (IYEAR .EQ. INTY) GO TO 50
0030                IF (TSUPL .LT. 0) TSK = 0.
0031                IF (TSUPL .GE. 0) TSK = 1.
0032                IF (TSUPL .GT. (-SUPLS(K)) .AND. TSK .EQ. 0) TSK = (TSUPL +
                   - SUPLS(K))/ SUPLS(K)
0033                SAVE = SUPLS(K)
0034                SUPLS(K) = SUPLS(K) * (1.+SPER(K)) * TSK
0035                IF (SUPLS(K) .LT. SAVE) SUPLS(K) = SAVE
0036                GO TO 70
0037             50 SUPLS (K) = SUPLSI(K)
0038                GO TO 70
0039             60 SUPLS (K) = 0.
0040             70 CONTINUE
0041                TOTSUP = SUPLS (1) + SUPLS (2) + SUPLS (3)
0042                IF (IYEAR - IYRS) 130,120,80
0043             80 GO TO(90,100,110), ISRTS
0044             90 I = IYEAR - IYRS
0045                SUPSCR = SUPSC(I)
0046                GO TO 140
0047            100 I = IYEAR - IYRS
0048                SUPSCR = SUPSI * (1.+SPERS)**I
0049                GO TO 140
0050            110 USCR = TSCR(IY-1) - SUPSCR
```

```
               IF (IYEAR .EQ. INTY) GO TO 120
               SUPSCR = USCR + SPERS *(USCR - PSCR)
               IF (SUPSCR .LT. TSCR(IY-1)) SUPSCR = TSCR(IY-1)
               PSCR = USCR
               GO TO 140
         120   SUPSCR = SUPSI
               PSCR = 0.
               GO TO 140
         130   SUPSCR = 0.
         140   CONTINUE
               TSCR(IY) = SUPSCR
               CALL AIRQ (IYEAR,AQDIF)
               CALL SUBPRI (NPLANT,AQDIF)
               CALL DEMAND (IYEAR,AQDIF,DEML,DEMS)
               PRINT 201, IYEAR
         201   FORMAT (///'      YEAR    19', I2)
               PRINT 499,SUPLS,TOTSUP,SUPSCR
         499   FORMAT (' SUPPLY LSC MTONS BY TYPE',3E12.4,' TOTAL',E12.4,' SUPPLY
              - FGD MW', E12.4)
         500   FORMAT (10E12.4)
               TSUPL = TOTSUP
               CALL ASSIGN (IYEAR,NPLANT,INTY,TOTSUP,SUPSCR,DEML,DEMS,ASSIG (1,IY)
              -))
               TSUPL = TSUPL - TOTSUP
               TSUPS = TSCR(IY) - SUPSCR
               PRINT 700, TSUPL, TOTSUP, TSUPS, SUPSCR
         700   FORMAT (//'  TOTAL OF ',F10.3,' MTONS OF LOW SULFUR COAL USED '/
              -'  EXCESS SUPPLY WAS ',F10.3,' MTONS'/'  TOTAL OF ',F10.2,
              - ' MW OF SCRUBBERS CURRENTLY INSTALLED'/'  EXCESS SUPPLY WAS ',
              - F10.2, ' MW')
               EXCOAL(IY) = TOTSUP
               EXSCR(IY) = SUPSCR
         200   CONTINUE
               RETURN
               END
```

```
FORTRAN IV G LEVEL  21                  AIRQ             DATE = 75070          08/28/03

 0001                  SUBROUTINE AIRQ(IYEAR,AQDIF)
 0002                  REAL AQDIF(300), AQSTD(300)
 0003                  COMMON /LOCATE/ NAME(3,300),CODE(3,300),STATE(300),AQCR(300),
                     - COUNTY(300),MINEMO(300),URBAN(300)
 0004                  COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
                     - BTULB(300)
 0005                  COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
                     - ECRAT(300),AGE(300)
 0006                  COMMON /STRAT/ NSTRAT,SYR(20),STAND(20),KIND(20)
 0007                  INTEGER SYR
 0008                  IY = IYEAR - 70
 0009                  IF (IYEAR .NE. SYR(1)) GO TO 20
 0010                  DO 10 N=1,NPLANT
 0011              10  AQSTD(N) = 1.E50
 0012                  GO TO 35
 0013              20  DO 30 N=1,NPLANT
 0014                  IF (CAP(N,IY) .LE. CAP(N,IY-1)) GO TO 30
 0015                  IF (CAP(N,IY-1) .EQ. 0) GO TO 100
 0016                  HTRAT(N) = (HTRAT(N)*CAP(N,IY-1)+(CAP(N,IY)-CAP(N,IY-1))*9000.)/
                     - CAP(N,IY)
 0017              30  CONTINUE
 0018              35  DO 60 I=1,NSTRAT
 0019                  IF (IYEAR .NE. SYR(I)) GO TO 60
 0020                  ITP = 0
 0021                  DO 50 N=1,NPLANT
 0022                  IF (CAP(N,IY) .EQ. 0) GO TO 50
 0023                  CALL FIT (I,N,IY,ITP,IN)
 0024                  IF (IN .EQ. 0) GO TO 50
 0025                  KI = KIND(I)
 0026                  GO TO (38,40,39,37),KI
 0027              37  Q = CAP(N,IY) * HTRAT(N) / 1.E3
 0028                  STAND(I) = 17.0 * Q**(-.33)
 0029                  IF (STAND(I) .GT. 6.0) STAND(I) = 6.0
 0030                  IF (STAND(I) .LT. 1.21) STAND(I) = 1.21
 0031              38  AQSTD(N) = STAND(I)
 0032                  GO TO 50
 0033              39  IF (ECRAT(N) .EQ. 0.) ECRAT(N) = 3.5
 0034              40  AQSTD(N) = STAND(I)*1.E6/(24.*0.9*CAP(N,IY)*1.E3*HTRAT(N))
 0035                  IF(KIND(I) .EQ. 3) AQSTD(N) = AQSTD(N)*2000./ECRAT(N)
 0036                  PRINT 306, (NAME(J,N),J=1,3),AQSTD(N),ECRAT(N)
 0037             306  FORMAT (3X,3A4,'  AQ STANDARD ',F12.4,' CONC/EMISS RATIO',F9.3)
 0038              50  CONTINUE
 0039              60  CONTINUE
 0040                  DO 70 N=1,NPLANT
 0041                  EMISH = SULPH(N)*2.E6/BTULB(N)
 0042                  AQDIF(N) = (EMISH - AQSTD(N))*BTUIN(N,IY)*1.E7
 0043                  IF (AQDIF(N) .LT. 0) AQDIF(N) = 0.
 0044              70  CONTINUE
 0045                  RETURN
 0046             100  DO 150 I=1,NSTRAT
 0047                  IF (IYEAR .LE. SYR(I)) GO TO 30
 0048                  ITP = 0
 0049                  CALL FIT (I,N,IY,ITP,IN)
 0050                  IF (IN .EQ. 0) GO TO 150
 0051                  KI = KIND(I)
```

```
FORTRAN IV G LEVEL  21                    AIRQ                DATE = 75070          08/28/03

                  GO TO (138,140,139,137),KI
          137     Q = CAP(N,IY) * HTRAT(N) / 1.E3
                  STAND(I) = 17.0 * Q**(-.33)
                  IF (STAND(I) .GT. 6.0) STAND(I) = 6.0
                  IF (STAND(I) .LT. 1.21) STAND(I) = 1.21
          138     AQSTD(N) = STAND(I)
                  GO TO 150
          139     IF (ECRAT(N) .EQ. 0.) ECRAT(N) = 3.5
          140     AQSTD(N) = STAND(I) *1.E6/(24.*0.9*CAP(N,IY)*1.E3*HTRAT(N))
                  IF (KIND(I) .EQ. 3) AQSTD(N) = AQSTD(N)*2000.*ECRAT(N)
          150     CONTINUE
                  GO TO 30
          500     FORMAT (/// '  PLANT NUMBER',I4,'IS NEW IN YEAR ',I4,
                - 'AND HAS NO AIR QUALITY STANDARD'///)
                  END
```

```
FORTRAN IV G LEVEL  21                    FIT                 DATE = 75070          08/28/03

                  SUBROUTINE FIT (I,N,IY,ITP,IN)
                  COMMON /LOCATE/ NAME(3,300),CODE(3,300),STATE(300),AQCR(300),
                - COUNTY(300),MINEMO(300),URBAN(300)
                  COMMON /STRAT/ NSTRAT,SYR(20),STAND(20),KIND(20),STA(20),SAQ(20),
                - SCOUN(20),SUR(20),SCMIN(20),SCMAX(20),SAMIN(20),SAMAX(20),AQS(20)
                  COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
                - BTULB(300)
                  COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
                - ECRAT(300),AGE(300)
                  DATA BLANK /'    '/, BLK1 /' '/
                  INTEGER STA, SAQ, STATE
                  IN = 0
                  IF (STA(I) .EQ. 0) GO TO 10
           70     IF (STA(I) .NE. STATE(N)) GO TO 150
           10     IF (SAQ(I) .EQ. 0) GO TO 20
                  NAQ = 0
                  DO 12 J=1,I
           12     NAQ = NAQ + SAQ(J)
                  NAQI = NAQ - SAQ(I) + 1
           80     DO 82 J=NAQI,NAQ
                  IF (AQCR(N) .EQ. AQS(J)) GO TO 20
           82     CONTINUE
                  GO TO 150
           20     IF (SCOUN(I) .EQ. BLANK) GO TO 30
           90     IF (SCOUN(I) .NE. COUNTY(N)) GO TO 150
           30     IF (SUR(I) .EQ. BLK1) GO TO 40
          100     IF (SUR(I) .NE. URBAN(N)) GO TO 150
           40     IF (SCMIN(I) .EQ. 0. .AND. SCMAX(I) .EQ. 0.) GO TO 50
          110     IF (SCMIN(I) .GE. CAP(N,IY) .OR. SCMAX(I) .LT. CAP(N,IY)) GO TO150
           50     IF (SAMIN(I) .EQ. 0. .AND. SAMAX(I) .EQ. 0.) GO TO 140
          120     IF (SAMIN(I) .GE. AGE(N) .OR. SAMAX(I) .LT. AGE(N)) GO TO 150
          140     IN = 1
          150     RETURN
                  END
```

```
FORTRAN IV G LEVEL  21                 SUBPRI              DATE = 75070          08/28/03

              SUBROUTINE SUBPRI (NPLANT,AQDIF)
              COMMON /PRI/ ORDER(300),NPRIOR,MAXP,MINP,PRIOR(300),PCOUNT(100),
             - LSCF(300),SCRF(300)
              REAL AQDIF(300)
              INTEGER ORDER,PRIOR,PCOUNT,P
              IF (NPRIOR .EQ. MAXP) NPRIOR = NPRIOR + 1
              DO 5 N=1,NPLANT
              IF (LSCF(N)  .NE. 3 .OR. PRIOR(N)  .EQ. MAXP  ) GO TO 5
              I = PRIOR(N) + 1
              PCOUNT(I) = PCOUNT(I) -1
              PRIOR(N)  = MAXP
              PCOUNT(NPRIOR) = PCOUNT(NPRIOR) + 1
            5 CONTINUE
              NO = 0
              NI = 0
              DO 40 K=1,NPRIOR
              P = NPRIOR - K
              DO 10 N=1,NPLANT
              IF (PRIOR(N) .NE. P) GO TO 10
              NO = NO + 1
              ORDER(NO) = N
           10 CONTINUE
              KB = NPRIOR - K + 1
              NCP = PCOUNT(KB)
              IF (NCP - 1) 40,35,15
           15 NCPM1 = NCP - 1
              DO 30 I=1,NCPM1
              II = I + 1
              DO 20 J=II,NCP
              IF (AQDIF(ORDER(NI+J)) .LE. AQDIF(ORDER(NI+I))) GO TO 20
              NTEMP = ORDER(NI+J)
              ORDER(NI+J) = ORDER(NI+I)
              ORDER(NI+I) = NTEMP
           20 CONTINUE
           30 CONTINUE
           35 NI = NI + NCP
           40 CONTINUE
              RETURN
              END
```

```
FORTRAN IV G LEVEL  21                 DEMAND              DATE = 75070          08/28/03

              SUBROUTINE DEMAND (IYEAR,AQDIF,DEML,DEMS)
              REAL AQDIF(300),DEML(3,300),DEMS(300)
              DATA EFF/.85/
              COMMON /LSCOAL/ NLSC,SUPLS(3),CMINE(3),ESFACM(3),CTRANS(3),
             - ESFACT(3),BTULSC(3),SULLSC(3),ISRT(3),SPER(3),IYRLS(3),
             - SUPLSI(3),SUPLSY(3,10)
              COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),BTULB(
             - 300)
              IY = IYEAR - 70
              DO 20 NP=1,NPLANT
              IF (CAP(NP,IY) .EQ. 0) GO TO 20
              SULH = SULPH(NP) / BTULB(NP)
              DO 10 I=1,NLSC
              SULL = SULLSC(I) / BTULSC(I)
              FRACL = AQDIF(NP)/(2.E13*BTUIN(NP,IY)*(SULH - SULL))
              IF (FRACL .LT. 0.) FRACL = 0.
           10 DEML(I,NP) = FRACL*BTUIN(NP,IY)*1.E13/(BTULSC(I)*2000.)*1.E-6
              EMISH = SULH*2.E6
              FRACS = AQDIF(NP)/(BTUIN(NP,IY)*1.E7*EFF*EMISH)
              DEMS (NP) = CAP(NP,IY) * FRACS
           20 CONTINUE
              RETURN
              END
```

```
      SUBROUTINE ASSIGN  (IYEAR,NPLANT,INTY,SUPLSC,SUPSCR,DEML,DEMS,
     - ASSIGN)
      INTEGER ORDER,ASSIGN(300),SCRF,PRIOR,PCOUNT
      REAL DEML(3,300),DEMS(300)
      COMMON /LOCATE/ NAME(3,300),CODE(3,300),STATE(300),AQCR(300),
     - COUNTY(300),MINEMO(300),URBAN(300)
      COMMON /PRI/ ORDER(300),NPRIOR,MAXP,MINP,PRIOR(300),PCOUNT(100),
     - LSCF(300),SCRF(300)
      IY = IYEAR - 70
      TEDLSC = 0.
      TEDSCR = 0.
      TPDLSC = 0.
      TPDSCR = 0.
      IF (IYEAR .NE. INTY) GO TO 20
   20 DO 80 N=1,NPLANT
      COST = 0.
      NP = ORDER(N)
      ASSIGN(NP) = 0
      WRITE (9,101) (NAME(I,NP),I=1,3), (CODE(I,NP),I=1,3)
  101 FORMAT (// ' ',3A4, 10X, A4, I3, I4)
      IF (DEML(1,NP) .EQ. 0. .AND. DEMS(NP) .EQ. 0) GO TO 50
      IF (LSCF(NP) .EQ.2 .AND. SCRF(NP) .EQ. 2) GO TO 120
      IF (LSCF(NP) .GE. 2) GO TO 30
      CALL LCOST(NP, DEML(1,NP), SUPLSC, COST, K, IY, AQLSC)
      IF (SUPLSC .LT. DEML(K,NP)) GO TO 30
      IF (AQLSC .EQ. 1) GO TO 30
      SUPLSC = SUPLSC - DEML(K,NP)
      ASSIGN(NP) = 2
   30 CONTINUE
      IF (SCRF(NP) .EQ. 2) GO TO 50
      CALL SCRUB (NP,DEMS(NP),SCOST,IY,AQFGD)
      IF (LSCF(NP) .EQ. 3) GO TO 48
      IF ((AQLSC.EQ.1.OR.ASSIGN(NP).EQ.0).AND.AQFGD.EQ.1) GO TO 58
      IF (AQLSC .EQ. 1 .AND. (SCOST-COST)/SCOST .GT. .15) GO TO 58
      IF (SUPSCR .GE. DEMS(NP)) GO TO 33
      IF (ASSIGN(NP) .EQ. 0) GO TO 52
      IF ((COST-SCOST)/COST .LT. .15) GO TO 60
      SUPLSC = SUPLSC + DEML(K,NP)
      GO TO 52
   33 IF (ASSIGN(NP) .EQ. 0) GO TO 40
      IF (AQFGD .EQ. 0) GO TO 34
      IF ((COST-SCOST)/COST .LT. .15) GO TO 60
      SUPLSC = SUPLSC + DEML(K,NP)
      GO TO 58
   34 IF (COST .LT. SCOST) GO TO 35
      IF (LSCF(NP) .EQ. 1 .AND. (COST-SCOST)/COST .LT. .15)GO TO 50
      GO TO 40
   35 IF (SCRF(NP) .NE. 1 .OR. (SCOST-COST)/SCOST .GT. .15) GO TO 50
   40 IF (SUPLSC .GE. DEML(K,NP) .OR. ASSIGN(NP) .EQ. 2) GO TO 48
      IF ((SCOST - COST)/SCOST .LT. .15) GO TO 48
      GO TO 52
   48 SUPSCR = SUPSCR - DEMS(NP)
      IF (ASSIGN(NP) .EQ. 2) SUPLSC = SUPLSC + DEML(K,NP)
      ASSIGN(NP) = 3
      LSCF(NP) = 3
```

```
 50  IF (ASSIGN(NP) .NE. 0) GO TO 60
 52  ASSIGN(NP) = 1
     TEDLSC = TEDLSC + DEML(1,NP)
     TEDSCR = TEDSCR + DEMS(NP)
     IF (COST .LT. SCOST) TPDLSC = TPDLSC + DEML(1,NP)
     IF(SCOST .LT. COST) TPDSCR = TPDSCR + DEMS(NP)
 55  WRITE (9,100) (NAME(I,NP),I=1,3),IYEAR,DEML(1,NP),DEMS(NP)
     GO TO 80
 58  ASSIGN(NP) = 4
     GO TO 55
 60  IF (ASSIGN(NP) .EQ. 3) GO TO 70
     WRITE (9,200) (NAME(I,NP),I=1,3),DEML(K,NP),K,IYEAR
     GO TO 80
 70  WRITE (9,300) (NAME(I,NP),I=1,3),DEMS(NP),IYEAR
 80  CONTINUE
     PRINT 600, TEDLSC,TPDLSC,TEDSCR,TPDSCR
600  FORMAT (//'  TOTAL EXCESS DEMAND FOR LSC IN M-TONS ',F12.2/
    - '  EXCESS DEMAND AT LEAST COST ',F12.2/'  TOTAL EXCESS DEMAND FOR
    - SCRUBBERS IN MW ',F12.2/'  EXCESS DEMAND AT LEAST COST ',F12.2)
     RETURN
120  PRINT 400, NP
     GO TO 80
100  FORMAT (' ***** ',3A4,'*****',          ' IS ASSIGNED TO BURN HIGH SU
    -LFUR COAL IN YEAR ',I5/'   ITS DEMAND FOR LSC WAS',F9.3,'M-TONS OR
    - FOR SCRUBBERS WAS ',F9.3,' MW')
200  FORMAT (' ***** ',3A4,'***** ',          ' IS ASSIGNED TO BURN',F8.3,
    -' M-TONS OF TYPE',I3,' LOW SULFUR COAL IN YEAR',I4)
300  FORMAT (' ***** ',3A4,' ***** ',         ') IS ASSIGNED A SCRUBBER OF'
    - ,F9.3,' MW IN YEAR ',I4)
400  FORMAT ('  PLANT NO. ',I5, ' CANNOT USE LOW SULFUR COAL OR A SCRUB
    -BER ')
     END
```

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FORTRAN IV G LEVEL  21                 LCOST                DATE = 75070        08/28/03

                SUBROUTINE LCOST (NP, DEML, SUPLSC, COST, K, IY, AQLSC)
                REAL DEML(3), LSCMKW,LPEN,LPENC
                COMMON /LSCOAL/ NLSC,SUPLS(3),CMINE(3),ESFACM(3),CTRANS(3),
               - ESFACT(3),BTULSC(3),SULLSC(3),ISRT(3),SPER(3),IYRLS(3),
               - SUPLSI(3),SUPLSY(3,10)
                COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
               - ECRAT(300),AGE(300), ESFHS,WETFR(300)
                COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
               - BTULB(300)
                DATA RC1/.175/, RC2/.31/, WETPR/35000./, DRYPR/10000./
                COMMON /COMPLY/ TCOAL(12),TSCR(12),EXCOAL(12),EXSCR(12),ASSIGN(300
               -,12),LCOST(300,12),FCOST(300,12)
                IYEAR = IY + 70
                AQLSC = 0.
                DO 9 J=1,NLSC
                IF (DEML(J).LE.BTUIN(NP,IY)*1.E7/(BTULSC(J)*2000.)) GO TO 9
                DEML(J) = BTUIN(NP,IY)*1.E7/(BTULSC(J)*2000.)
                WRITE (9,101)
            101 FORMAT('    PLANT CANNOT MEET AQ STANDARD WITH LSC')
                AQLSC = 1.
              9 CONTINUE
                HSCYR = HSCOST(NP)*(1.+ESFHS)**(IY-4)*1.331
                WRITE (9,630) HSCYR,DEML
            630 FORMAT (' CURRENT HSC CENTS MBTU',E15.4,'     DEMAND LSC MTONS',3E1
               -5.4)
                UTIL = BTUIN(NP,IY) / 8760.E-10 / HTRAT(NP) / CAP(NP,IY)
                LPEN = 0.0
                IF (UTIL .LE. 0.2) LPEN = 1.70
                IF (UTIL .GT. 0.2 .AND. UTIL .LE. 0.3) LPEN = 1.12
                IF (UTIL .GT. 0.3 .AND. UTIL .LE. 0.4) LPEN =  .83
                IF (UTIL .GT. 0.4 .AND. UTIL .LE. 0.5) LPEN =  .64
                IF (UTIL .GT. 0.5 .AND. UTIL .LE. 0.6) LPEN =  .52
                IF (UTIL .GT. 0.6 .AND. UTIL .LE. 0.7) LPEN =  .41
                IF (UTIL .GT. 0.7 .AND. UTIL .LE. 0.8) LPEN =  .36
                IF (UTIL .GT. 0.8) LPEN =  .29
                TOTSUP = SUPLS(1) + SUPLS(2) + SUPLS(3)
                USED = TOTSUP - SUPLSC
                PARTSP = 0.
                DO 10 K=1,NLSC
                LEFT = SUPLS(K) + PARTSP - USED
                IF (LEFT .GT. 0) GO TO 20
                PARTSP = PARTSP + SUPLS(K)
             10 CONTINUE
                GO TO 50
             20 IF (LEFT .LT. DEML(K)) GO TO 30
             21 CTRANS(K) = 6.3 +.600     /DEML(K)
                IF (CTRANS(K) .GT. 11. ) CTRANS(K) = 11.
                COST = DEML(K) * (CMINE(K) * (1.+ESFACM(K))**(IYEAR-IYRLS(K))  +
               - CTRANS(K) * MILES(NP) * (1.+ESFACT(K))**(IYEAR-IYRLS(K)) / 1000.)
                CMLSC = COST/(DEML(K)*BTULSC(K)*2.E-5)
                GO TO 40
             30 IF (K .EQ. NLSC) GO TO 50
                EXDEM = DEML(K) - LEFT
                CTRANS(K) = 6.3 +.600     /LEFT
                CTRANS(K+1) = 6.3 +.600     / EXDEM
```

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FORTRAN IV G LEVEL  21                    LCOST              DATE = 75070          08/28/03
 0049               COST = LEFT * (CMINE(K) * (1.+ESFACM(K))**(IYEAR-IYRLS(K))   +
                  - CTRANS(K) * MILES(NP) * (1.+ESFACT(K))**(IYEAR-IYRLS(K)) / 1000.)
                  - + EXDEM * (CMINE(K+1) * (1.+ESFACM(K+1))**(IYEAR-IYRLS(K+1)) +
                  - CTRANS(K+1)*MILES(NP)*(1.+ESFACT(K+1))**(IYEAR-IYRLS(K+1))/1000.)
 0050               CMLSC = COST/((LEFT*BTULSC(K) + EXDEM*BTULSC(K+1))*2.E-5)
 0051            40 LPENC = LPEN*CAP(NP,IY)*UTIL*8760.*DEML(K)*BTULSC(K)*2.E-4/BTUIN(N
                  -P,IY)
 0052               IF (CMLSC .GE. HSCYR) GO TO 42
 0053               HSCOST(NP) = HSCOST(NP) * CMLSC / HSCYR
 0054               HSCYR = CMLSC
 0055            42 COST = COST*1.E6 + HSCYR*1.E5*(BTUIN(NP,IY)-DEML(K)*BTULSC(K)
                  - * 2.E-4)
 0056               LSCMKW = CMLSC*HTRAT(NP)/1.E5
 0057               WRITE (9,200) CMLSC, LSCMKW
 0058           200 FORMAT (' LSC FUEL              CENTS MBTU',F10.4,'     MILS KWHR',
                  -F10.4)
 0059               LPENC = LPENC * (1.+ESFHS)**(IY-4)
 0060               HUBNO = LPENC / (CAP(NP,IY)*UTIL*8760.)
 0061               WRITE (9,99) UTIL, HUBNO
 0062            99 FORMAT (' ANNUAL CAPACITY FACTOR ',F9.3,' SYSTEM PENALTY ',F10.2,'
                  -  MILS KWHR ')
 0063               CMALL = COST/(BTUIN(NP,IY)*1.E5)
 0064               ALLMKW = CMALL*HTRAT(NP)/1.E5
 0065               WRITE (9,201) CMALL, ALLMKW, COST
 0066           201 FORMAT (' LSC + HSC FUEL    CENTS MBTU',F10.4,'     MILS KWHR',F10.
                  -4,'     ANNUAL DOLLARS',E14.6)
 0067               RC = RC1
 0068               IF (AGE(NP) .LT. 50) RC = RC2
 0069               CAPBOT = CAP(NP,3)
 0070               IF (CAP(NP,IY) .LT. CAPBOT) CAPBOT = CAP(NP,IY)
 0071               CAPBOT = CAPBOT *(DEML(K)*BTULSC(K)/BTUIN(NP,IY)*2.E-4)
 0072               ANBOTC = CAPBOT *((1.-WETFR(NP))*DRYPR + WETFR(NP)*WETPR) * RC
 0073               BBOTC = ANBOTC/RC
 0074               COST = COST + ANBOTC + LPENC
 0075               ANKW = COST/ BTUIN(NP,IY)*HTRAT(NP)/1.E10
 0076               WRITE (9,2002) BBOTC, ANBOTC
 0077          2002 FORMAT(' CONVERSION COST ',E15.6,'     ANNUALIZED ',E15.6)
 0078               WRITE (9,2003) COST, ANKW
 0079          2003 FORMAT (' ANNUAL TOTAL COST     ',E14.6,'     MILS KWHR',F10.4)
 0080               LCOST(NP,IY) = COST - (HSCYR * 1.E5 * BTUIN(NP,IY))
 0081               RETURN
 0082            50 CONTINUE
 0083               K = 3
 0084               GO TO 21
 0085           100 FORMAT (/// '  LOW SULFUR COAL RAN OUT WHILE SUPPLYING PLANT NO.',
                  - I4, ' IN YEAR ',I4)
 0086               RETURN
 0087               END
```

```
      SUBROUTINE SCRUB (NP, DEMS, SCOST, IY, AQFGD)
      COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
     - ECRAT(300),AGE(300), ESFHS
      COMMON /SCRUBB/ ISRTS,SPERS,IYRS,SUPSI,ESFSC,ISTYPE,STYPE(5)
      COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
     - BTULB(300)
      COMMON /COMPLY/ TCOAL(12),TSCR(12),EXCOAL(12),EXSCR(12),ASSIGN(300
     -,12),LCOST(300,12),FCOST(300,12)
      INTEGER STYPE
      RC = .175
      CIN = 0.
      SULFY = SULPH(NP) * BTUIN(NP,IY) / BTULB(NP) * 5.E9
      IF (CAP(NP,IY) .GT. CAP(NP,1)) CIN = CAP(NP,IY) - CAP(NP,1)
      IF (AGE(NP) .LT. 50) RC = .31
      UTIL = BTUIN(NP,IY) / 8760.E-10 / HTRAT(NP) / CAP(NP,IY)
      SPEN = 0.
      IF (UTIL.LE.0.2) SPEN = 5.85
      IF (UTIL.GT.0.2 .AND.UTIL .LE. 0.3) SPEN = 3.42
      IF (UTIL.GT.0.3 .AND.UTIL .LE. 0.4) SPEN = 2.43
      IF (UTIL.GT.0.4 .AND.UTIL .LE. 0.5) SPEN = 1.85
      IF (UTIL.GT.0.5 .AND.UTIL .LE. 0.6) SPEN = 1.54
      IF (UTIL.GT.0.6 .AND.UTIL .LE. 0.7) SPEN = 1.34
      IF (UTIL.GT.0.7 .AND.UTIL .LE. 0.8) SPEN = 1.24
      IF (UTIL .GT.0.8) SPEN = 1.05
      IF (DEMS .GE. 25.) GO TO 8
      DEMS = 25.
      IF (CAP(NP,IY) .LT. 25.) DEMS = CAP(NP,IY)
    8 AQFGD = 0.
      IF (DEMS .LE.CAP(NP,IY)) GO TO 9
      DEMS = CAP(NP,IY)
      WRITE (9,101)
  101 FORMAT ('  PLANT CANNOT MEET AQ STANDARD WITH SCRUBBER')
      AQFGD = 1.
    9 CONTINUE
      SPENC = SPEN*CAP(NP,IY)*UTIL*8760./1.21
      IF (ISTYPE .GT. 1) GO TO 20
      CALL SCRUBC (CAP(NP,IY), UTIL,         FLGRT(NP), SULFY, STYPE(1),
     - RC, CIN, ANCOST)
   10 SCOST= (ANCOST+SPENC)/CAP(NP,IY)*DEMS*(1.+ESFSC)**(IY-4)*1.21
      FCOST(NP,IY) = SCOST
      ANCMKW =  SCOST/(CAP(NP,IY)*UTIL*8760.  )
      ANCKW = SCOST/(CAP(NP,IY)*1.E3)
      WRITE (9,99) UTIL, SPEN
   99 FORMAT (' ANNUAL CAPACITY FACTOR ',F9.3,'    SYSTEM PENALTY ',F10.
     -2,' MILS KWHR ')
      WRITE (9,100) SCOST, ANCMKW, ANCKW, DEMS
  100 FORMAT (' ANNUAL FGD COST       ',E14.6,'    MILS KWHR',F10.4,'
     -DOLLARS PER KW',F10.4,'  SIZE MW ',F10.3)
      SCOST = SCOST + BTUIN(NP,IY) * HSCOST(NP)*1.331*(1.+ESFHS)**(IY-4)
     - *1.E5
      SCMKW = SCOST/(CAP(NP,IY)*UTIL*8760.  )
      WRITE (9,200) SCOST, SCMKW
  200 FORMAT (' ANNUAL FGD + HSC COST',E14.6,'    MILS KWHR',F10.4)
      RETURN
   20 SCOST = 1.E50
```

```
FORTRAN IV G LEVEL  21                  SCRUB                DATE = 75070          08/28/03

 0049                DO 30 I=1,ISTYPE
 0050                CALL SCRUBC( CAP(NP,IY), UTIL,          FLGRT(NP), SULFY, STYPE(I),
                   - RC, CIN, ANCOST)
 0051                IF (ANCOST .GE. SCOST) GO TO 30
 0052                SCOST = ANCOST
 0053                K = I
 0054             30 CONTINUE
 0055                ANCOST = SCOST
 0056                GO TO 10
 0057                END


FORTRAN IV G LEVEL  21                  SCRUBC               DATE = 75070          08/28/03

 0001                SUBROUTINE SCRUBC  (CAP,LF,F,SULFY,STYPE,RC,CIN,ANCOST)
 0002                REAL *4 LF,LO,MAN,IC,IU,DS(5),DA(5),UA(5)
 0003                INTEGER STYPE
 0004                DATA US/.77/, LO/225000./, EFF/.85/, MAN/.075/, DO/.15/,
                   - IC/.38/, IU/.18/, DS/2*15.05,3*12.20/,DA/425.,230.,600.,540.,635.
                   - /, UA/68.,68.,18.,45.,44./
 0005                Q = CAP * F
 0006                SULF = SULFY / 8760.
 0007                N = CAP / 150  + .99
 0008                FS = 6.67 * N**.2 * CAP**(-.35)
 0009                FR = 1.5 - .24 / 550. * CAP
 0010                IF (FR .LT. 1.2) FR = 1.2
 0011                EXP = .33
 0012                IF (STYPE .EQ. 5) EXP = .18
 0013                FA = (5./SULF)**EXP
 0014                SR = SULF * EFF / CAP * 2.
 0015                DSS = (DS(STYPE) - 1.5*CIN/CAP)
 0016                COST = (DSS * FS * FR + DA(STYPE) * FA * SR) * (1.+DO) *
                   - (1.+IC) * (1.+IU) * CAP * 1000.
 0017                CCC= COST/(CAP*1.E3    )
 0018                ANCOST = (US * Q + SULFY * UA(STYPE)) * LF + LO + MAN * LF * COST
                   -    + RC * COST
 0019                ACC = ANCOST / CAP * 1.E-3
 0020                WRITE (9,300) STYPE, CCC, ACC
 0021            300 FORMAT (' SCRUBBER(',I3,') CAP COST PER KW',F10.4,'     ANNUAL COST
                   - PER KW',F10.4)
 0022                SPART = ((US*Q + SULFY*UA(STYPE))*LF)/(CAP*1.E3)
 0023                GPART = (LO + MAN*LF*COST)/(CAP*1.E3)
 0024                CPART = (RC*COST)/(CAP*1.E3)
 0025                WRITE (9,301) SPART, GPART, CPART
 0026            301 FORMAT ('    S HANDLING',E12.6,' O&M',E12.6,' CAP CHG',E12.6,' $ P
                   -ER KW ')
 0027                RETURN
 0028                END
```

```
0001           SUBROUTINE OUTPUT (INTY,TCAP)
0002           COMMON /PLANT/ NPLANT,CAP(300,12),BTUIN(300,12),SULPH(300),
              - BTULB(300)
0003           COMMON /EX/ HTRAT(300),HSCOST(300),MILES(300),FLGRT(300),
              - ECRAT(300),AGE(300),ESFHS,WETFR(300)
0004           COMMON /LOCATE/ NAME(3,300),CODE(3,300),STATE(300),AQCR(300),
              - COUNTY(300),MINEMO(300),URBAN(300)
0005           COMMON /COMPLY/ TCOAL(12),TSCR(12),EXCOAL(12),EXSCR(12),ASSIGN(300
              -,12),LCOST(300,12),FCOST(300,12)
0006           INTEGER ASSIGN,YEAR(12)
0007           DATA YEAR/'1971','1972','1973','1974','1975','1976','1977',
              -'1978','1979','1980','1981','1982'/
0008           DATA BLK/'    '/, EX/'X   '/
0009           REAL COST(12),TCAP(12),SKWHR(12),COMPLY(12),COMCAP(12),TCOST(12)
0010       102 FORMAT ('1   RESPONSE AND COST IN MILS/KWHR FOR PLANTS'/
              - 15X,'0 -- PLANT DOES NOT EXIST'/
              - 15X,'1 -- BURNS HIGH SULFUR COAL'/15X,'2 -- BURNS LOW SULFUR COAL
              -'/15X,'3 -- INSTALLS SCRUBBER'/15X,'4 -- COMPLIANCE NO POSSIBLE WI
              -TH PRESENT STANDARDS'//' PLANT NAME',4X,8(9X,A4)//)
0011       101 FORMAT ('1   RESPONSE AND ANUAL DOLLAR COST OF PLANTS'/
              - 15X,'0 -- PLANT DOES NOT EXIST'/
              - 15X,'1 -- BURNS HIGH SULFUR COAL'/15X,'2 -- BURNS LOW SULFUR COAL
              -'/15X,'3 -- INSTALLS SCRUBBER'/15X,'4 -- COMPLIANCE NO POSSIBLE WI
              -TH PRESENT STANDARDS'//' PLANT NAME',4X,8(9X,A4)//)
0012       601 FORMAT ('1  PLANTS WHICH ARE NOT IN COMPLIANCE WITH AIR QUALITY ST
              -ANDARDS'/'      WITH YEARS OF NON-COMPLIANCE INDICATED'//
              -'  PLANT NAME',3X,8(9X,A4)/)
0013       100 FORMAT (/1X,3A4,8I13)
0014       200 FORMAT (16X,8F13.0)
0015       400 FORMAT (16X,8F13.3)
0016       300 FORMAT (///'   TOTAL COST (IN DOLLARS) OF LOW SULFUR COAL AND SCRU
              -BBERS FOR ALL PLANTS IN THE REGION'/16X,8F13.0)
0017       500 FORMAT (///'      AVERAGE COST (IN MILS/KWHR) OF LOW SULFUR COAL AN
              -D SCRUBBERS FOR ALL PLANTS IN THE REGION'/16X,8F13.3)
0018       600 FORMAT (1X,3A4,8(9X,A4))
0019       700 FORMAT (///'      TOTAL CAPACITY (IN MEGAWATTS) OF ALL PLANTS IN THE
              -E REGION'/'       WHICH ARE NOT IN COMPLIANCE WITH AIR QUALITY STAN
              -NDARDS'/16X,8F13.2)
0020       702 FORMAT (///'      TOTAL CAPACITY (IN MEGAWATTS) OF ALL PLANTS IN THE
              -E REGION'/'       WHICH ARE IN COMPLIANCE WITH AIR QUALITY STANDAR
              -DS'/16X,8F13.2)
0021           INT = INTY - 70
0022           DO 10 IY=INT,12
0023           COMCAP(IY) = 0.
0024           SKWHR(IY) = 0.
0025        10 TCOST(IY) = 0.
0026           PRINT 101, (YEAR(IY),IY=INT,12)
0027           DO 20 NP=1,NPLANT
0028           DO 18 IY=INT,12
0029           COST(IY) = 0.
0030           IF(CAP(NP,IY) .EQ. 0.) ASSIGN(NP,IY) = 0
0031           IF (ASSIGN(NP,IY) .EQ. 2) COST(IY) = LCOST(NP,IY)
0032           IF (ASSIGN(NP,IY) .EQ. 3) COST(IY) = FCOST(NP,IY)
0033        18 TCOST(IY) = TCOST(IY) + COST(IY)
0034           PRINT 100, (NAME(I,NP),I=1,3),(ASSIGN(NP,IY),IY=INT,12)
```

```
 20  PRINT 200, (COST(IY),IY=INT,12)
     PRINT 300, (TCOST(IY),IY=INT,12)
     PRINT 102, (YEAR(IY),IY=INT,12)
     DO 30 NP=1,NPLANT
     DO 28 IY=INT,12
     COST(IY) = 0.
     IF (ASSIGN(NP,IY) .EQ. 2) COST(IY) = LCOST(NP,IY)/BTUIN(NP,IY)*
    - HTRAT(NP)*1.E-10
     IF (ASSIGN(NP,IY) .EQ. 3) COST(IY) = FCOST(NP,IY) / BTUIN(NP,IY)
    - * HTRAT(NP) * 1.E-10
     IF (ASSIGN(NP,IY) .EQ. 2 .OR. ASSIGN(NP,IY) .EQ. 3)
    - SKWHR(IY) = SKWHR(IY) + BTUIN(NP,IY) / HTRAT(NP)
 28  CONTINUE
     PRINT 100, (NAME(I,NP),I=1,3),(ASSIGN(NP,IY),IY=INT,12)
 30  PRINT 400, (COST(IY),IY=INT,12)
     DO 32 IY=INT,12
 32  SKWHR(IY) = TCOST(IY) / SKWHR(IY) * 1.E-10
     PRINT 500, (SKWHR(IY),IY=INT,12)
     PRINT 601, (YEAR(IY),IY=INT,12)
     DO 40 NP=1,NPLANT
     DO 34 IY=INT,12
 34  COMPLY(IY) = BLK
     NC = 0
     DO 38 IY=INT,12
     IF (ASSIGN(NP,IY) .EQ. 4) GO TO 35
     IF (ASSIGN(NP,IY).NE. 1 .OR. LCOST(NP,IY).LT.1.) GOTO 36
 35  NC = 1
     COMPLY(IY) = EX
     GO TO 38
 36  COMCAP(IY) = COMCAP(IY) + CAP(NP,IY)
 38  CONTINUE
     IF (NC.NE.0) PRINT 600, (NAME(I,NP),I=1,3),(COMPLY(IY),IY=INT,12)
 40  CONTINUE
     PRINT 702, (COMCAP(IY),IY=INT,12)
     DO 42 IY=INT,12
 42  COMCAP(IY) = TCAP(IY) - COMCAP(IY)
     PRINT 700, (COMCAP(IY),IY=INT,12)
     RETURN
     END
```

APPENDIX II. AIR QUALITY ANALYSIS

The ratio of ground level concentration to power plant emissions is required for input to the policy evaluation model. The data needed to construct this ratio was obtained primarily from a study conducted by Walden,[1] Research Division of Abcor, Inc., for the U.S. Environmental Protection Agency. Maximum 24-hr ground level concentrations were computed in that study for power plants in 51 Air Quality Control Regions. These estimates, along with the corresponding emission levels, have been incorporated into the data base for strategy evaluation.

Estimates of ground level concentration for power plants within the five-state study region, but not modeled by Walden, were computed using the procedure described below. Emission levels and stack characteristics for these plants were determined using data obtained from the 1971 Federal Power Commission Form 67 and by assuming that coal-fired boilers are operating at 90% of rated capacity throughout the day.

The 24-hr ground level concentrations were computed using a single source Gaussian plume model similar to the one employed by Walden. The dispersion equation accounts for multiple reflection of the plume from the ground and the stable layer above as suggested by Bierly and Hewson.[2] The model uses diffusion coefficients based on Turner[3] and the plume rise equation proposed by Briggs.[4] The equations used in the model are listed at the end of this section. Ground level concentrations are computed at specified distances downwind and crosswind for a given set of meteorological conditions (i.e., temperature, wind speed, stability class, and mixing height). In order to estimate maximum concentrations, a low wind speed of 2.5 mps, as suggested by EPA[5] and the Tennessee Valley Authority,[6] and moderately unstable atmospheric conditions (Stability Class B) were assumed. The annual afternoon mixing height as determined from Ref. 7 was also input to the model.

The dispersion equation provides an estimate of 1-hr average concentrations. To account for the daily variability of the weather conditions, the 1-hr calculated concentration is divided by 4, as suggested by EPA,[5] to obtain a 24-hr concentration. This assumes that the wind direction on the day on which the critical wind speed occurs persists in one direction for 6 of the 24 hours.

In cases where power plants are located in proximity, maximum ground level concentrations were computed by summing the contributions of each interacting plant at the desired location. Maximum ground level concentrations occur when the wind direction is parallel to a line connecting the two plants. A local maximum concentration is found downwind of the downwind power plant. When the wind is assumed to come from the opposite direction, a second local maximum concentration is found. The larger of these two values was conservatively used in computing the concentration to emission ratio for both power plants. The applicability of the wind speed and direction was checked by comparing the assumed values with monthly average values reported in the Climatological Data, National Summary before the results were added to the data base.

The modeling procedure described above contains numerous assumptions and limitations that limit its predictive accuracy for specific applications. As a result of these limitations, an additional site-specific evaluation of air quality should be performed for each power plant prior to implementation of any strategy based on the results of the air quality analysis performed in this study.

The Plume Dispersion Equation used is presented below:

$$\chi(x,0,z;H) = \frac{Q}{2\Pi\, u\, \sigma_y\, \sigma_z} \left\{ \exp\left[-\frac{1}{2} \left(\frac{z - H}{\sigma_z} \right)^2 \right] \right.$$

$$+ \exp\left[\left(-\frac{1}{2}\, \frac{z + H}{\sigma_z} \right)^2 \right] + \sum_{N=1}^{N=J} \left[\exp -\frac{1}{2} \left(\frac{z - H - 2\,NL}{\sigma_z} \right)^2 \right.$$

$$+ \exp -\frac{1}{2} \left(\frac{z + H - 2\,NL}{\sigma_z} \right)^2 + \exp -\frac{1}{2} \left(\frac{z - H + 2\,NL}{\sigma_z} \right)^2$$

$$\left. \left. + \exp -\frac{1}{2} \left(\frac{z + H + 2\,NL}{\sigma_z} \right)^2 \right] \right\} ,$$

where

x = concentration

Q = emission rate

u = wind velocity

σ_y, σ_z = dispersion coefficients

H = height at which the plume levels off

L = height of the stable layer

J = number of interactions necessary to include the important reflections ;

if $\sigma_y/L \geq 1.6$ trapping model is used ,

$$\chi = \frac{Q}{\sqrt{2\Pi}\,\sigma_y\, Lu} \exp\left[-\frac{1}{2}\left(\frac{y}{\sigma_y}\right)^2\right] .$$

Plume Rise Equations:

Neutral and Unstable Conditions

$$\Delta h = 1.6\, F^{1/3}\, u^{-1}\, x^{2/3} \qquad \text{when } x < 3.5\, x^*$$

$$\Delta h = 1.6\, F^{1/3}\, u^{-1}\, (3.5\, x^*)^{2/3} \qquad \text{when } x > 3.5\, x^* \quad ,$$

where

$$x^* = 14\text{m}\, (F/\text{m}^4/\text{sec}^3)^{5/8} \qquad \text{when } F < 55\ \text{m}^4/\text{sec}^3$$

$$x^* = 34\text{m}\, (F/\text{m}^4/\text{sec}^3)^{5/8} \qquad \text{when } F > 55\ \text{m}^4/\text{sec}^3 \quad ,$$

and

Δh = plume rise

F = buoyancy flux

u = wind speed

x^* = critical downwind distance .

Stable Conditions

$$\Delta h = 2.9\left(\frac{F}{us}\right)^{1/3} ,$$

where

$$s = (g/T)\,\frac{\partial\Theta}{\partial z} ,$$

and

T = absolute air temperature

g = acceleration of gravity

$\frac{\partial\Theta}{\partial z}$ = temperature gradient of the atmosphere .

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APPENDIX III. FGD COST MODEL

CAPITAL COSTS

$$C = (D_s F_s F_r + D_a F_a S_r)(1 + D_o)(1 + I_c)(1 + I_u)$$

D_s = Scrubbing process direct capital costs (\$/kw)
Costs for 500 Mw, 4 module basis plant. Cost includes scrubber with electrical and structural work, ductwork, fans, pumps, and reheat.

D_s = 13.55 \$/kw new plants
= 15.05 \$/kw old plants

For lime/limestone process

F_s = Gas flow rate and scrubber configuration adjustment factor.
Ratio of plant direct costs to the basis plant.

$F_s = 6.67(n^{.20})/(Q^{.35})$

n = number of modules required by the plant

Q = total plant size in Mw

F_r = Retrofit difficulty factor
Reflects the relative difficulty of retrofit as a function of plant size and age.

F_r = 1.00 new plants
= 1.26-1.51 old plants

D_a = Alkali handling direct capital costs (\$/lb S/hr)
Costs for 500 Mw, 3.5% S coal basis plant.

D_a = 425 (\$1b S/hr) for lime/limestone process

F_a = Sulfur rate scale factor
Ratio of base case sulfur removal rate to removal rate of plant in question.

$F_a = (S/5)^{-.33}$

S = plant sulfur removal rate tons/hr

S_r = Plant sulfur rate (lb S/hr/kw)
Rate at which plant scrubber will generate sulfur.

S_r = function of fuel S content, scrubber efficiency, plant size.

D_o = Other process direct costs
Other direct costs as a percentage of direct costs.

D_o = 0.15 (15%)

I_c = Contractor indirect costs
Indirect costs of construction as a percentage of total direct costs.

$I_c = 0.38$ (38%)

I_u = User indirect costs
Indirect costs to user not included in construction costs as a percentage of total investment cost.

$I_u = 0.18$ (18%)

ANNUALIZED COSTS

$$A = (U_s Q + 8760\ U_a S)L + L_o + MLC + R_c$$

U_s = Scrubber utility cost ($/scfm/yr)
Cost of electric power, steam and material supplies on an annual basis.

$U_s = 0.77$ $/scfm/yr for all processes

Q = Design flue gas rate scfm
Flue gas rate of plant in question.

Q = 2 scfm/kw default value

U_a = Alkali handling utility cost $/ton of S
Cost of power and material supplies for alkali handling including waste disposal and product sale.

$U_a = 68$ $/ton for lime/limestone process

S = Design sulfur removal rate (tons/hr)
Rate at which sulfur is generated by the plant in question.

S = function of fuel S content and scrubber efficiency

L = Plant annual load factor
Data input for each plant.

L_o = Operating labor and overhead cost $/yr
Estimated value for operations.

$L_o = 225{,}000$ $/yr

M = Maintenance costs as a fraction of investment
Costs for maintenance and overhead at full load.

M = .075 (7.5%)

C = Total capital investment ($) from previous equation

R_c = Capitalization rate
Capital charges for depreciation, profit, taxes, and insurance.

$R_c = .175$ (17.5%)

APPENDIX IV. SYSTEM COST CALCULATIONS

SYSTEM DESCRIPTION

The peak demand to be met by the system is 6130 Mw. The structure of the monthly loads is such that a summer peak is assumed and no unit maintenance is scheduled during June, July, and August. The generating units are grouped on the basis of size and forced outage rate as follows:

Group	Number	Type	Size (Mw)	Forced Outage Rate
1	1	Nuc.	800	0.10
2	3	F	600	.07
3	4	F	300	.05
4	8	F	150	.05
5	10	F	100	.03
6	10	F	60	.04
7	8	GT	50	.05

The nuclear unit in Group 1 is of modest size; units in Groups 2-5 are fossil-fired, steam-electric type. Group 6 represents the oldest class of steam units; Group 7 contains combustion turbines for peaking and emergency service. The average size of a unit in Groups 2-6 is 165 Mw, which represents the expected average size of fossil units in 1976.

The calculational procedure involves dividing the year into 26 two-week periods for purposes of scheduling maintenance; the duration and distribution of unit maintenance is:

Group	2 Weeks	4 Weeks	6 Weeks	8 Weeks
1	-	-	-	1
2	-	3	-	-
3	-	3	-	1
4	6	-	2	-
5	8	2	-	-
6	7	3	-	-
7	-	-	-	-

On this basis, the scheduled outage plus peak load during a two-week period ranges from about 4700 Mw in early spring and fall to 6130 Mw in the summer.

Power from other utilities is available to the reference system. Firm purchases are 250 Mw during the 12 summer weeks; in addition, 400 Mw of additional capacity are assumed available, but not scheduled. (In the calculations, the 400 Mw are actually used by the system.) The reference system reserve margin is calculated to be 19%. This corresponds to a loss-of-capacity of once in four years.

The other characteristics of the system will be described under cost factors.

COST FACTORS

All the costs are based on a nominal end of 1974 economic conditions (before impact of coal mine labor contract conditions are known). Fuel costs and annual average heat rates can be specified on a unit-by-unit basis; however, for the purposes of these approximate calculations, all units with a given size have equal heat rates, except, of course, the unit being studied that has flue gas treatment or uses low sulfur Western coal.

For any utility in the five-state region under study, coal costs will vary from plant to plant. In addition, the coal costs recently have undergone large changes. For the year 1972, the U.S. electric utility average coal cost was 38.2¢/MBtu.* For the month of May in 1973, the average purchase price by utilities was 39.5¢/MBtu.** By May of 1974, the purchase price had increased to about 66¢/MBtu. In this same publication, the average coal price was 65¢/MBtu for the five-state area being investigated. To account for real costs in 1976, the price (1974 dollars) of high sulfur coal is assumed to be 70¢/MBtu for all electrical generating units of 150 Mw or more. For all smaller units, which consume only a small amount of coal and which may also burn some low sulfur coal, the average price is assumed to be 80¢/MBtu. The combustion turbines are assumed to burn mainly distillate oil and a small amount of natural gas; the average price is estimated to be 180¢/MBtu. Two alternative calculations are made for prices of low sulfur fuel. An 80¢/MBtu price, which in part is based on the Asbury and Costello report,*** is used in conjunction

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*Steam-Electric Plant Factors, 1973 Edition, National Coal Association, Jan. 1974.

**FPC News, Aug. 30, 1974.

***Price and Availability of Western Coal, ANL/ES-37, Dec. 1974.

with the 70¢/MBtu regular fuel cost. The other alternative price is 90¢/MBtu for low sulfur coal. Thus, the basic fuel price differential for the units will be 10¢ and 20¢/MBtu.

The annual heat rates for the plants are:

Group	Size	Heat Rate (Btu/kw-hr)
1	800	10500
2	600	9400
3	300	9650
4	150	10300
5	100	11000
6	60	12500
7	50	13000

For the fossil-fired, steam-electric generating units, the system average heat rate is about 9700 Btu/kw-hr. This is a good steam-electric heat rate on a system basis; in 1971, only four systems in the U.S. had heat rates lower than this.*

Heat rate adjustments are made for the units that burn low sulfur fuel or use flue gas desulfurization. The addition of a flue gas desulfurization reduces the plant output by 2-7%.** Estimates of reduced output caused by burning low sulfur fuel are more difficult to find. High moisture can seriously reduce capacity. For this study, a 5% increase in the heat rate will be used for flue gas treatment plants; a 2-1/2% increase will be applied to units using low sulfur fuel. These penalties are somewhat arbitrary, but reasonable.

The operating and maintenance costs for the steam-electric plants using fossil fuel were formulated based on a constant cost per kw ($2/kw), plus a cost per kw-hr ($0.8 \frac{\text{mills}}{\text{kw-hr}}$) generated for 600- and 300-Mw units. For a system with a 50% capacity factor, the average O & M cost would be 1.3 mills/kw-hr. As a comparison, the 1971 cost for all fossil-fuel, steam-electric plants in the U.S. was 0.94 mills/kw-hr at ∿ 54% capacity factor. In the November 1973 issue of Electrical World, the 18th steam-electric survey

*FPC, Steam-Electric Plant Construction Cost and Annual Production Expenses - 1971, Feb. 1973.

**Radian Corporation, Factors Affecting Ability to Retrofit Flue Gas Desulfurization Systems, Dec. 1973.

indicated that for new plants operating throughout 1972 and with initial commercial operation after 1970, the O & M cost was 0.72 mills/kw-hr for units with an average capacity factor of about 58%. Based on past comparisons, it would be expected that the O & M cost for these large (~ 740 Mw, average) modern units would be lower than the average for a complete system.

The operation and maintenance cost for the unit using flue gas desulfurization techniques was assumed to be the same as the base unit, plus an O & M cost for the flue gas treatment adjunct. The incremental O & M annual cost was assumed to be proportional to the size of the unit and the amount of sulfur to be removed (this assumed removal of about 80% of 3-1/2% sulfur coal). The cost factors are:

	600 Mw	300 Mw	150 Mw
$/kw	3.5	4.	4.6
$/ton of sulfur	52	60	69

These estimates were based on the paper by Burchard at the "Technical Conference on Sulfur in Utility Fuels: The Growing Dilemma."* For a 300-Mw plant at 50% capacity factor using 3-1/2% sulfur fuel, this cost amounts to about 1.7 mills/kw-hr. As can be seen, these numbers are rather specific; however, there are many proposed commercial processes. The cost factors are selected to yield a general indication of the incremental costs and the estimated operation and maintenance costs vary considerably among them.

The incremental O & M costs for units using low sulfur fuel have not been extensively documented. In general, there is a need to handle much more fuel in the coal yard, as well as in the coal crushing, pulverizing and feeding equipment. Ash removal from the flue gas and handling problems are increased. Operational problems influenced by slagging characteristics of the coal, as well as increased ash load on furnace, generally contribute to higher maintenance and operating costs. For the purposes of this study, the O & M conventional costs are increased by 10% to account for the use of low sulfur fuel in old facilities.

The last major cost item included is the assignment of costs for incremental capacity needed to maintain system reliability. This includes the capability penalty not only for any increased forced outage rates but

*Electrical World, Proceedings on Technical Conference Sulfur in Fuels, Chicago, Oct. 25-26, 1972.

also the penalty for derating the units with flue gas treatment equipment or burning low sulfur fuel. The annual penalty is estimated to be $30/kw of needed capability. This cost may be thought of as the annual capital costs for combustion turbines purchased for peaking, or as a cost of demand capability purchased during the peak-load season (also possibly at other times of the year), or as an incremental cost to provide additional capability with the construction of a new generating unit.

CALCULATIONS AND RESULTS

Three nominal sizes of generating units were studied: 150, 300, and 600 Mw. The investigations were made by varying the loading order of each of these units in the reference system. For example, the costs and performance were calculated for the 600-Mw unit in the 2, 4, 8, and 16 positions of the loading order sequence. The capacity factor varied from about 80% in the number 2 position to about 10% in the number 16 position. Three system calculations were made for each position:

1. The reference unit with no FGD equipment but using high sulfur coal.
2. The reference unit with FGD equipment.
3. The reference unit burning low sulfur fuel.

In addition, calculations were made to illustrate the impact of various incremental forced outage rates for units using FGD. (The incremental forced outage range studied was from 0 to 0.15.) For units burning low sulfur fuel, the two cases calculated were for 80-90¢/MBtu fuel. These fuel prices corresponded to incremental costs of 10-20¢/MBtu fuel for the level of system used. A complete set of calculations was initially intended for each reference size; however, the results indicated that size was not an important parameter in the comparison of the operational penalty (when expressed in mills/kw-hr).

The system performance in terms of annual cost for fuel and operation and maintenance, together with the reliability in terms of megawatts needed to meet the reliability criterion of loss-of-capacity once in four years, were estimated for the reference unit with no FGD equipment, but using high sulfur fuel. Similar calculations were then made for the FGD and low sulfur fuel cases. Cost differentials were calculated under the label of four factors:

1. System fuel consumption.

2. System operations and maintenance variations.

3. Capability needed to meet reliability criterion.

4. Incremental O & M requirements for FGD or low sulfur fuel alternatives.

The sum of these four cost differentials is called the operational penalty for use of either alternative. In the utility response simulation, the incremental O & M cost for FGD was not included since the scrubber cost model accounts for this factor (see App. III).

The results are plotted in Fig. IV.1. Some information on runs made is given schematically in Table IV.1.

The contributions of the four factors varied from case to case; however, the variations in system O & M costs were consistently small (2%) and could easily be neglected in future calculations. In contrast, the incremental O & M required for FGD was always a large fraction of the total cost.

The incremental forced outage rate for a unit with the FGD equipment was assumed to be 0.1. In order to observe the impact of other forced outage rates, cases were calculated over the range from 0 to 0.15. Some results are shown in Figs. IV.2 and IV.3, including and excluding, respectively, the incremental O & M due to FGD equipment. Figure IV.3 additionally presents results that show the impact of capacity factor on the relationship between penalty and forced outage rate -- the slope of the curve becomes steeper with lower capacity factor.

Table IV.1. System Cost Estimations

-- Output of nominal unit 600, 300, and 150 Mw.

-- Output with the FGD decreased by 5%; base cases with incremental forced outage rate of 0.10.

-- Output with low sulfur fuel decreased by 2-1/2%; base cases with incremental forced outage rate of 0.02.

600 Mw:

L.O.	Capacity Factor	Inc. Operating Cost Mills 1 kw-hr
Nominal Unit (70¢/MBtu fuel)		
2	0.821	-
4	.818	-
8	.548	-
16	.137	-
FGD (70¢/MBtu fuel)		
2	0.728	2.393
4	-	-
8	.494	3.115
16	.127	9.643
LSC (80¢/MBtu fuel)		
2	0.816	1.475
4	-	-
8	.535	1.628
16	.134	2.948

300 Mw (similar runs)

150 Mw (similar runs)

Forced outage variations of 0, 0.05, and 0.15 for 600, 300, and 150 Mw unit with FGD.

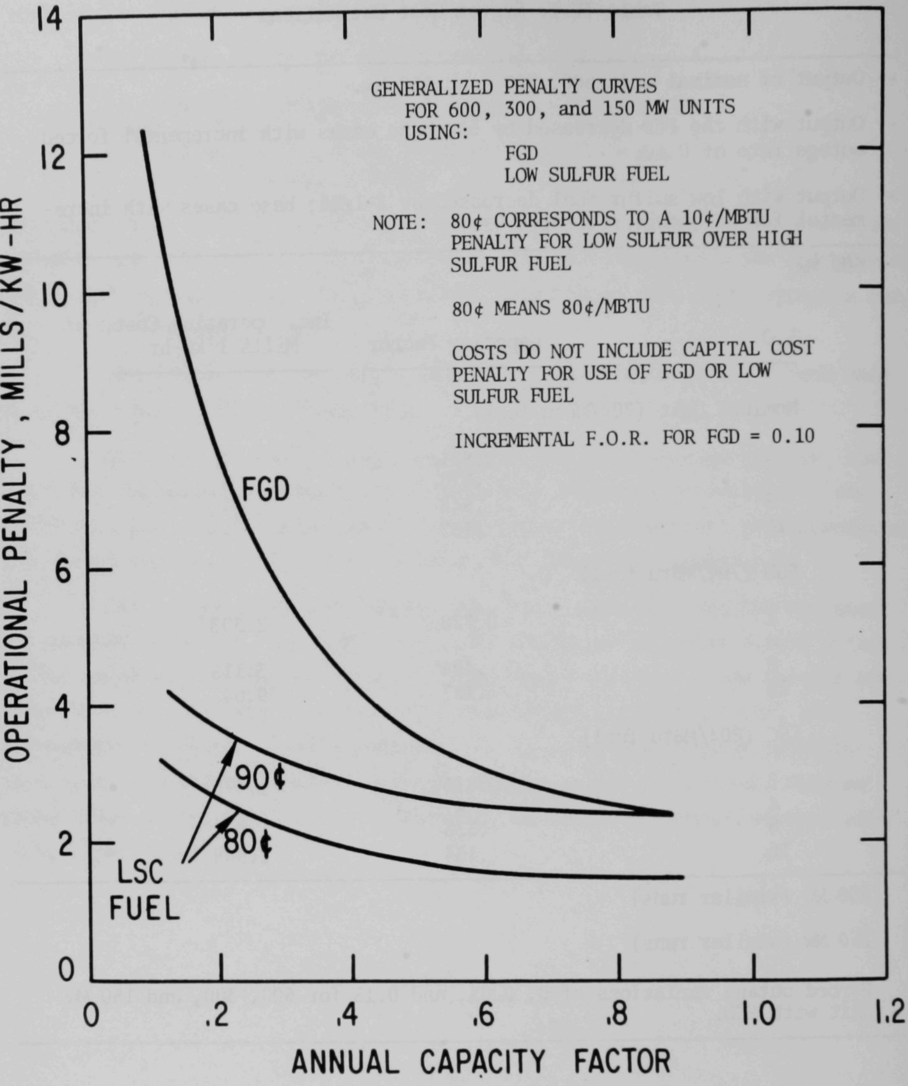

Fig. IV.1. Generalized Operational Penalty Curves - FGD O&M Included

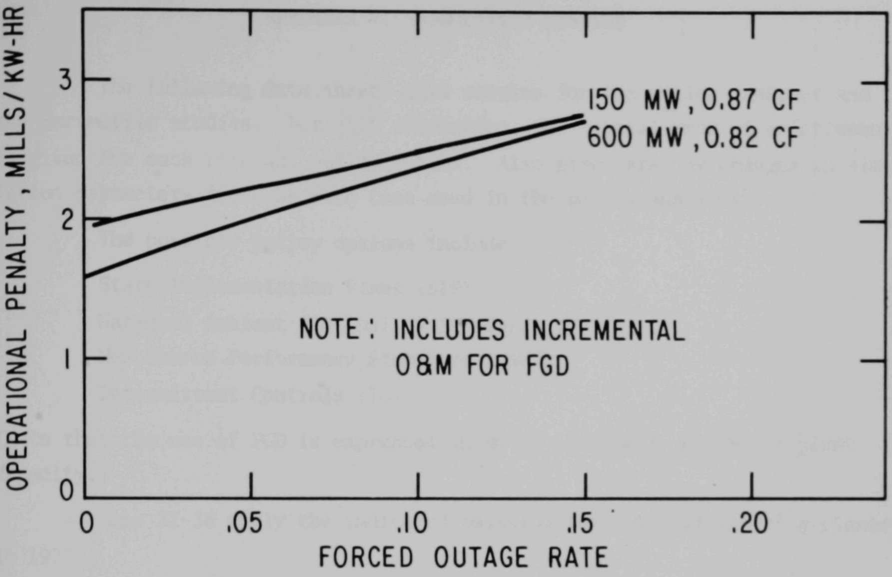

Fig. IV.2. Operational Penalty vs Forced Outage Rate - FGD O&M Included

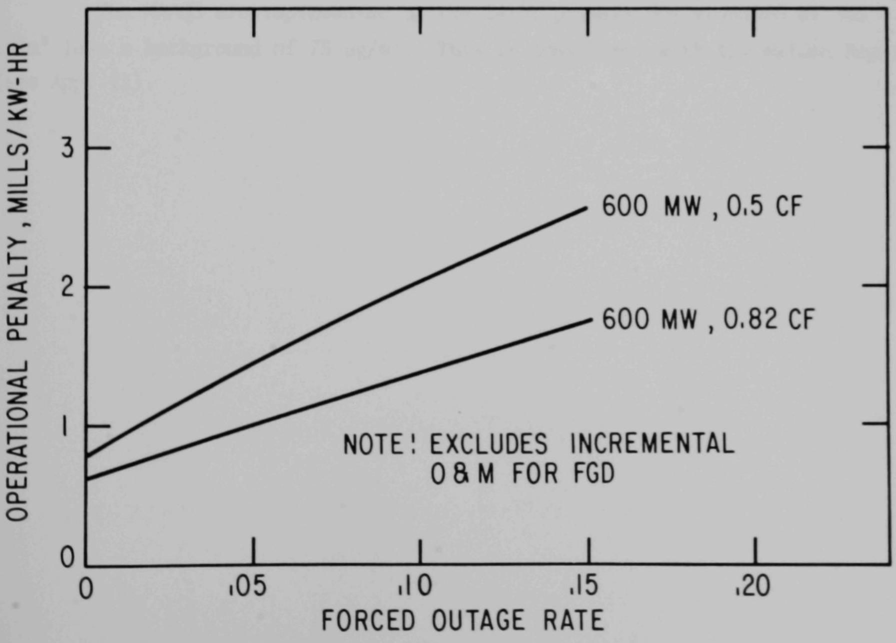

Fig. IV.3. Operational Penalty vs Forced Outage Rate - FGD O&M Excluded

APPENDIX V. SIMULATION RESULTS

The following data sheets give results for the policy analyses and the parametric studies. For each simulation, the initial year of enforcement is given for each relevant policy option. Also given are any changes in simulation parameters from the base case used in the policy analyses.

The possible policy options include:

State Implementation Plans (SIP)
National Ambient Air Quality Standards (NAAQS)
New Source Performance Standards (NSPS)
Intermittent Controls (IC)

(Note that the use of FGD is expressed in Mw of scrubbers, not Mw of plant capacity.)

Runs 31-36 apply the indicated emission limit to all existing plants in 1977.

All costs are in 1974 $.

The NAAQS are represented by the 24-hr primary SO_2 standard of 365 $\mu g/m^3$ less a background of 75 $\mu g/m^3$. This is consistent with the Walden Report (see App. II).

No.	Policy: SIP	NAAQS	NSPS	IC		Parametric Changes
10	1975	-	1975	-		None
2	1977	-	1975	-		
29	1977	-	1977	-		
3	1980	-	1975	-		
30	1980	-	1977	-		
4	-	1975	1975	-		None
5	-	1977	1975	-		
6	-	1977	1977	-		
7	-	1980	1975	-		
8	-	1980	1977	-		
9	-	1980	1980	-		
12	1975	-	1975	-	urban	None
	-	1980	1975	1975	rural	
31	-	-	1977	-		1977 - 1.21 lb SO_2/MBtu
32	-	-	1977	-		" 1.50 "
33	-	-	1977	-		" 2.00 "
34	-	-	1977	-		" 2.50 "
35	-	-	1977	-		" 3.00 "
36	-	-	1977	-		" 3.50 "

No.	Policy					Parametric Changes
	SIP	NAAQS	NSPS	IC		
13	1975	-	1975	-		No system reliability costs
14	-	1975	-	-		"
45	-	1977	1977	-	urban	No system reliability costs
	-	1980	1977	1977	rural	and 0% cost difference in assignment
17	1975	-	1975	-		0% cost difference in assignment
18	-	1975	1975	-		"
46	-	1977	1977	-		"
44	-	1977	1977	-	urban	"
	-	1980	1977	1977	rural	
15	1975	-	1975	-		10% cost difference in assignment
16	-	1975	1975	-		"
48	-	1977	1977	-		"
47	1975	-	1975	-		50% cost difference in assignment
42	-	1977	1977	-		"
43	-	1977	1977	-	urban	"
	-	1980	1977	1977	rural	
50	-	1977	1977	-		Annual cost of LSC raised <u>5%</u>
37	-	1977	1977	-		" <u>10%</u>
38	-	1977	1977	-		" <u>15%</u>
39	-	1977	1977	-		" <u>20%</u>

No.	Policy SIP	NAAQS	NSPS	IC	Parametric Changes
40	-	1977	1977	-	Annual cost of LSC raised 25%
41	-	1977	1977	-	" 30%
52	-	1977	1977	-	" 35%
51	-	1977	1977	-	" 40%
19	1975	-	1975	-	Annual cost of LSC raised 20%
20	-	1975	1975	-	"
21	1975	-	1975	-	Annual cost of FGD raised 20%
22	-	1975	1975	-	"
23	1975	-	1975	-	LSC boiler conversion cost decreased 50%
24	-	1975	1975	-	"
27	1975	-	1975	-	Supply growth of FGD decreased
28	-	1975	1975	-	"
25	1975	-	1975	-	Supply growth of LSC increased
26	-	1975	1975	-	"
49	-	1977	1977	-	"
53	1975	-	1975	-	F.O.R. increase of 0.05 in FGD system cost
54	-	1975	1975	-	"
55	1975	-	1975	-	F.O.R. increase of 0.00 in FGD system cost
56	-	1975	1975	-	"

No.: 2 Policy: SIP 1977 NSPS 1980 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	9.6	0	0.88	0	0	69.48	0	0.37	0.53	2.10
1976	14.2	14.1	3.9	0.88	0	0	72.14	1.09	0.62	0.86	2.32
1977	25.2	25.2	140.0	0.88	0.87	0	18.98	57.79	1.51	7.96	2.56
1978	34.1	34.1	137.0	2.74	2.74	0	24.37	55.19	2.43	9.97	2.64
1979	45.3	45.3	121.2	6.74	6.66	0	32.63	50.75	4.31	13.21	2.97
1980	60.0	60.0	87.4	15.11	15.06	0	48.55	38.79	7.51	15.47	3.18
1981	79.6	79.6	72.9	33.12	19.42	0	65.50	26.74	10.27	15.68	3.13
1982	106.1	106.1	52.4	33.12	19.44	0	76.09	20.22	11.86	15.59	3.02
									38.88	Total	

No.: 3 Policy: SIP 1980 NSPS 1975 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	9.6	0	0.88	0	0	69.48	0	0.37	0.53	2.10
1976	14.2	14.1	3.9	0.88	0	0	72.15	1.09	0.62	0.86	2.32
1977	25.2	22.9	0	0.88	0	0	76.77	0	0.98	1.28	2.13
1978	31.1	30.5	0	0.88	0	0	79.56	0	1.20	1.51	1.92
1979	39.9	39.8	2.1	0.88	0	0	82.80	0.59	1.57	1.90	1.91
1980	51.7	51.7	147.3	0.88	0.87	0	27.54	59.80	2.41	8.75	2.11
1981	67.2	67.2	141.5	2.74	2.74	0	34.41	57.83	3.96	11.51	2.49
1982	87.4	87.4	122.6	6.74	6.70	0	45.58	50.72	6.69	14.68	2.89
									17.80	Total	

No.: 4 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	53.3	0.88	0.86	0.20	28.79	40.69	0.88	3.06	1.84
1976	17.2	17.2	52.4	2.71	2.69	0.20	33.04	40.19	1.38	4.18	1.96
1977	29.1	29.1	48.5	6.64	6.64	0.02	44.35	32.42	3.22	7.26	2.37
1978	38.8	38.8	25.7	15.12	12.98	0	67.13	12.43	5.42	8.07	2.12
1979	51.3	51.3	23.3	26.63	13.38	0	71.50	11.89	6.26	8.76	2.19
1980	67.5	67.5	16.3	26.63	13.83	0	78.56	8.77	7.35	9.36	2.24
1981	88.9	88.9	7.7	26.63	13.83	0	86.73	5.51	8.61	9.93	2.27
1982	117.7	117.7	0	26.63	13.83	0	94.25	2.06	9.72	10.31	2.31
									42.84	Total	

No.: 5 Policy: NAAQS 1977 NSPS 1975 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	10.2	0	0.88	0.69	0	67.88	1.60	0.60	0.88	2.54
1976	14.2	14.1	4.5	2.16	0.69	0	70.14	3.09	0.83	1.18	2.62
1977	25.2	25.2	68.1	2.16	2.14	0.21	32.66	44.11	1.77	5.42	2.30
1978	34.1	34.1	55.7	5.27	5.27	0.17	41.67	37.89	2.94	7.06	2.26
1979	45.3	45.3	30.6	12.01	11.98	0.03	64.67	18.71	5.32	8.23	2.06
1980	60.0	60.0	25.0	26.42	14.40	0	74.34	13.00	7.17	9.64	2.26
1981	79.6	79.6	19.5	26.42	14.47	0	81.60	10.65	8.63	10.56	2.39
1982	106.1	105.4	0	26.42	14.47	0	94.25	2.06	10.20	10.82	2.38
									37.46	Total	

No.: 6 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	77.13	0.88	0.86	0.42	28.97	47.81	1.28	4.42	2.38
1978	30.3	30.3	70.4	2.71	2.67	0.21	35.68	43.88	2.15	6.02	2.26
1979	40.6	40.6	57.8	6.62	6.61	0.17	46.71	36.67	3.73	7.98	2.34
1980	54.1	54.1	26.9	15.03	14.42	0	71.73	15.61	6.72	9.37	2.25
1981	72.2	72.2	27.7	31.21	14.46	0	78.67	13.58	8.18	10.40	2.38
1982	96.8	96.8	8.13	31.21	14.48	0	90.21	6.10	9.74	10.80	2.38
									31.80 Total		

No.: 7 Policy: NAAQS 1980 NSPS 1975 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	10.3	0	0.88	0.69	0	69.88	1.60	0.60	0.86	2.54
1976	14.2	14.1	4.5	2.16	0.69	0	70.14	3.09	0.83	1.18	2.62
1977	25.2	23.7	0	2.16	1.05	0	74.93	1.85	1.33	1.77	2.42
1978	34.1	31.3	0	2.16	1.17	0	77.72	1.85	1.60	2.06	2.21
1979	45.3	42.0	0	2.16	1.54	0	81.54	1.85	2.15	2.64	2.18
1980	60.0	60.0	69.7	2.33	2.31	0.07	44.48	42.85	3.68	8.27	2.31
1981	79.6	79.6	58.5	3.96	3.95	0.04	53.75	38.50	5.47	10.18	2.51
1982	106.1	106.1	22.7	7.48	7.48	0.04	74.40	21.91	8.19	11.01	2.45
									23.85	Total	

No.: 8 Policy: NAAQS 1980 NSPS 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	21.9	5.9	0.88	0	0	73.30	3.47	1.00	1.36	2.24
1978	30.2	29.4	5.8	0.88	0	0	76.12	3.44	1.28	1.68	2.06
1979	40.6	39.8	7.2	0.88	0	0	79.56	3.82	1.72	2.16	2.00
1980	54.1	54.1	78.5	0.88	0.86	0.03	40.64	46.69	2.75	6.77	2.10
1981	72.2	72.2	72.6	2.71	2.69	0.04	50.28	41.96	4.68	9.31	2.44
1982	96.8	96.8	40.2	6.62	6.60	0.04	66.35	29.96	7.37	11.11	2.57
									18.80	Total	

No.: 9 Policy: NAAQS 1980 NSPS 1980 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-
1980	28.2	28.2	109.1	0.88	0.88	0.04	32.92	54.41	1.25	3.80	1.54
1981	36.2	36.2	113.5	2.76	2.74	0.04	38.37	53.87	2.28	5.94	2.02
1982	46.6	46.6	96.4	6.74	6.72	0	50.62	45.70	3.57	7.05	1.92
									7.10	Total	

No.: 10 Policy: SIP 1975 NSPS 1975 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	98.4	0.88	0.87	8.37	14.78	54.70	0.92	6.22	2.89
1976	17.3	17.3	121.4	2.74	2.74	2.41	17.93	55.30	1.56	8.70	2.96
1977	29.1	29.1	118.9	6.76	6.71	0	27.69	49.08	3.40	12.28	3.13
1978	38.8	38.8	86.8	15.24	15.22	0	44.65	34.91	6.16	13.80	3.04
1979	51.3	51.3	71.2	33.52	18.73	0	55.13	28.25	7.96	14.44	3.05
1980	67.5	67.5	67.8	33.52	19.71	0	61.60	25.73	9.15	14.85	3.05
1981	88.9	88.9	60.8	33.52	19.71	0	69.19	23.05	10.66	15.41	3.07
1982	117.7	117.7	36.1	33.52	19.74	0	81.64	14.67	12.43	15.22	2.97
									52.24	Total	

No.: 12

Policy:
SIP Urban 1975
IC Rural 1975
NAAQS Rural 1980
NSPS 1975

Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	74.8	0.88	0.85	2.01	35.07	34.41	0.81	2.31	2.78
1976	17.2	17.2	83.5	2.66	2.65	0	38.97	34.26	1.46	3.75	3.00
1977	29.1	29.1	65.8	6.53	6.46	0	48.37	28.40	3.05	6.30	3.13
1978	38.8	38.8	46.2	14.67	11.43	0	62.25	17.32	4.79	7.69	2.91
1979	51.3	51.3	44.5	22.10	11.43	0	67.04	16.34	5.53	8.25	2.89
1980	67.5	67.5	57.4	22.10	16.61	0	65.01	22.33	8.08	12.43	2.70
1981	88.9	88.9	48.9	27.75	16.61	0	72.42	19.83	9.46	13.06	2.73
1982	117.7	117.7	25.6	27.75	16.61	0	85.26	11.05	11.22	13.16	2.68
									44.40	Total	

No.: 13   Policy: SIP 1975 NSPS 1975   Parametric Changes: System reliability penalty deleted

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	79.3	0.88	0.87	13.93	14.57	54.91	0.73	5.01	2.37
1976	17.2	17.2	85.7	2.73	2.72	12.12	17.64	55.60	1.19	6.75	2.31
1977	29.1	29.1	79.4	6.70	6.70	10.37	27.83	48.94	2.66	9.56	2.38
1978	38.8	38.8	65.9	15.26	15.24	5.50	41.27	38.29	4.70	11.39	2.44
1979	51.3	51.3	28.7	33.61	31.63	0	70.67	12.72	8.18	11.57	2.42
1980	67.5	67.5	23.2	66.86	33.02	0	77.94	9.39	9.24	11.86	2.42
1981	88.9	88.9	16.0	66.86	33.02	0	85.69	6.56	10.32	12.04	2.41
1982	117.7	113.0	0	66.86	33.03	0	96.13	0.18	11.71	12.18	2.43
									48.73	Total	

No.: 14 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: System reliability penalty deleted

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	37.6	0.88	0.86	7.75	28.79	40.69	0.72	2.50	1.50
1976	17.2	17.2	37.2	2.71	2.68	7.72	32.56	40.68	1.18	3.62	1.74
1977	29.1	29.1	31.3	6.61	6.60	6.13	43.46	33.32	2.66	6.12	2.01
1978	38.8	38.8	15.2	15.02	15.02	1.78	59.48	20.08	4.47	7.52	2.01
1979	51.3	51.3	3.6	33.11	19.76	0	80.55	2.84	5.98	7.42	1.79
1980	67.5	65.6	0	33.11	20.07	0	86.49	0.84	6.66	7.70	1.81
1981	88.9	81.4	0	33.11	20.07	0	91.40	0.84	7.40	8.10	1.84
1982	117.7	95.3	0	33.11	20.07	0	95.47	0.84	8.01	8.39	1.87
									37.08	Total	

No.: 15 Policy: SIP 1975 NSPS 1975 Parametric Changes: 10% cost difference in response assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	98.4	0.88	0.87	8.37	14.78	54.70	0.93	6.29	2.89
1976	17.2	17.2	121.5	2.74	2.74	2.41	17.92	55.31	1.56	8.70	3.00
1977	29.1	29.1	119.1	6.77	6.74	0	31.84	44.93	3.35	10.52	2.61
1978	38.8	38.8	86.9	15.34	15.07	0	45.57	33.99	6.07	13.32	2.95
1979	51.3	51.3	85.2	32.98	15.07	0	50.11	33.28	6.77	13.51	2.89
1980	67.5	67.5	83.7	32.98	15.32	0	55.24	32.09	7.72	13.98	2.88
1981	88.9	88.9	75.2	32.98	15.32	0	63.14	29.11	9.26	14.66	2.92
1982	117.7	117.7	52.1	32.98	15.34	0	74.97	21.34	11.15	14.87	2.88
									46.81	Total	

No.: 16 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: 10% cost difference in response assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	53.3	0.88	0.86	2.02	28.79	40.69	0.88	3.06	1.84
1976	17.2	17.2	52.4	2.71	2.70	2.02	33.04	40.19	1.38	4.18	1.96
1977	29.1	29.1	47.3	6.64	6.63	0.17	47.78	28.99	3.23	6.76	2.08
1978	38.8	38.8	33.3	15.10	10.46	0	61.59	17.97	4.73	7.68	2.05
1979	51.3	51.3	30.9	18.69	10.85	0	65.95	17.43	5.53	8.39	2.12
1980	67.5	67.5	23.9	18.69	11.31	0	73.02	14.32	6.60	9.04	2.18
1981	88.9	88.9	15.4	18.69	11.31	0	81.66	10.58	7.92	9.70	2.22
1982	117.7	112.7	0	18.69	11.31	0	94.25	2.06	9.34	9.91	2.22
									39.61	Total	

No.: 17 Policy: SIP 1975 NSPS 1975 Parametric Changes: 0% cost difference in response assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	102.2	0.88	0.19	8.18	13.89	55.59	0.68	4.90	2.56
1976	17.2	17.2	131.0	0.88	0.19	2.41	14.74	58.49	0.77	5.22	2.29
1977	29.1	29.1	143.9	0.88	0.19	0	19.97	56.80	1.46	7.31	2.35
1978	38.8	38.8	144.6	0.88	0.19	0	23.21	56.35	1.91	8.23	2.32
1979	51.3	51.3	142.9	0.88	0.44	0	26.65	56.74	2.53	9.49	2.35
1980	67.5	67.5	141.5	0.88	0.44	0	32.88	54.46	3.22	9.72	2.23
1981	88.9	88.9	133.1	0.98	0.44	0	40.48	51.76	4.62	11.41	2.39
1982	117.7	117.7	110.1	0.98	0.44	0	51.70	44.61	6.79	13.13	2.60
									21.98	Total	

No.: 18 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: 0% cost difference in response assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	55.5	0.88	0.42	1.85	28.39	41.09	0.76	2.68	1.67
1976	17.2	17.2	61.2	1.31	0.42	1.85	29.93	43.31	0.82	2.74	1.56
1977	29.1	29.1	72.8	1.31	0.42	0	34.52	42.25	1.67	4.84	2.05
1978	38.8	38.8	71.0	1.31	0.42	0	37.93	41.63	2.07	5.46	2.02
1979	51.3	51.3	70.0	1.31	0.42	0	41.70	41.69	2.66	6.38	2.06
1980	67.5	67.5	63.9	1.31	0.60	0	47.50	39.83	3.59	7.56	2.14
1981	88.9	88.9	55.5	1.31	0.60	0	57.53	34.72	4.98	8.66	2.18
1982	117.7	117.7	31.6	1.31	0.60	0	70.32	25.99	6.73	9.57	2.22
									23.28	Total	

No.: 19 Policy: SIP 1975 NSPS 1975 Parametric Changes: LSC annual cost raised 20%

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	52.5	0.88	0.86	21.91	14.58	54.90	1.25	8.57	3.98
1976	17.2	17.2	66.1	2.72	2.72	18.26	17.45	55.78	2.02	11.57	3.97
1977	29.1	29.1	68.3	6.70	6.70	15.56	26.55	50.23	4.48	16.87	4.25
1978	38.8	38.8	50.5	15.23	15.21	8.92	40.92	38.65	7.48	18.28	3.91
1979	51.3	51.3	19.0	33.54	33.53	1.87	67.61	15.78	13.75	20.34	4.16
1980	67.5	67.5	7.3	72.92	37.73	0	84.19	3.15	16.70	19.84	4.06
1981	88.9	88.9	0	72.92	38.51	0	92.24	0	19.21	20.83	4.22
1982	117.7	98.6	0	72.92	39.09	0	96.31	0	20.91	21.71	4.34
									85.80	Total	

No.: 20 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: LSC annual cost raised 20%

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	14.5	0.88	0.86	14.91	28.79	40.69	1.23	4.27	2.59
1976	17.2	17.2	22.9	2.71	2.68	12.37	32.56	40.68	2.00	6.14	2.94
1977	29.1	29.1	8.8	6.61	6.60	12.61	45.23	31.54	4.39	9.70	3.12
1978	38.8	38.8	3.8	15.01	15.00	2.95	63.12	16.44	7.35	11.64	3.09
1979	51.3	51.3	0	33.05	20.88	0	82.62	0.77	10.19	12.33	2.98
1980	67.5	63.1	0	33.52	21.20	0	86.68	0.66	11.39	13.14	3.08
1981	88.9	76.8	0	33.52	21.97	0	91.58	0.66	13.02	14.22	3.23
1982	117.7	89.5	0	33.52	22.55	0	95.65	0.66	14.49	15.15	3.38
									64.06	Total	

No.: 21 Policy: SIP 1975 NSPS 1975 Parametric Changes: FGD annual cost raised 20%

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	120.2	0.88	0.87	3.26	14.78	54.70	0.97	6.56	3.03
1976	17.2	17.2	133.1	2.74	2.74	0	17.93	55.30	1.68	9.37	3.20
1977	29.1	29.1	119.3	6.74	6.66	0	31.77	45.01	3.59	11.30	2.79
1978	38.8	38.8	89.3	15.11	14.45	0	45.54	34.02	6.40	14.05	3.14
1979	51.3	51.3	87.6	31.2	14.45	0	50.08	33.31	7.11	14.20	3.06
1980	67.5	67.5	86.2	31.2	14.70	0	55.21	32.12	8.09	14.65	3.04
1981	88.9	88.9	77.6	31.2	14.70	0	63.11	29.14	9.65	15.29	3.06
1982	117.7	117.7	54.6	31.2	14.70	0	74.92	21.39	11.54	15.40	3.00
									49.03	Total	

No.: 22 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: FGD annual cost raised 20%

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	63.0	0.88	0.86	0	28.79	40.69	0.92	3.20	1.92
1976	17.2	17.2	62.1	2.71	2.70	0	33.04	40.20	1.47	4.45	2.10
1977	29.1	29.1	49.2	6.64	6.63	0	44.90	31.88	3.40	7.57	2.45
1978	38.8	38.8	35.0	15.08	9.93	0	62.00	17.56	4.91	7.92	2.11
1979	51.3	51.3	34.0	17.04	9.96	0	65.98	17.41	5.62	8.52	2.16
1980	67.5	67.5	27.5	17.04	10.29	0	72.08	15.26	6.74	9.35	2.25
1981	88.9	88.9	19.0	17.04	10.29	0	81.02	11.22	8.12	10.02	2.31
1982	117.7	115.0	0	17.04	10.29	0	94.25	2.06	9.78	10.38	2.32
									40.96	Total	

No.: 23 Policy: SIP 1975 NSPS 1975 Parametric Changes: LSC boiler conversion cost reduced by half

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	116.1	0.88	0.87	4.31	14.78	54.70	0.90	6.09	2.81
1976	17.2	17.2	133.1	2.74	2.74	0	17.93	55.30	1.55	8.64	2.94
1977	29.1	29.1	118.9	6.75	6.71	0	27.69	49.08	3.34	12.06	3.07
1978	38.8	38.8	86.8	15.24	15.22	0	44.65	34.91	6.11	13.68	3.01
1979	51.3	51.3	74.2	33.52	18.05	0	54.23	29.15	7.64	14.09	2.98
1980	67.5	67.5	72.3	33.52	18.43	0	59.49	27.84	8.66	14.56	2.98
1981	88.9	88.9	65.2	33.52	18.43	0	67.08	25.16	10.13	15.10	2.99
1982	117.7	117.7	40.6	33.52	18.45	0	80.39	15.92	11.82	14.70	2.87
									50.15	Total	

No.: 24 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: LSC boiler conversion cost reduced by half

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	62.3	0.88	0.86	0.17	28.79	40.69	0.85	2.95	1.78
1976	17.2	17.2	61.4	2.71	2.70	0.17	33.04	40.20	1.37	4.15	1.95
1977	29.1	29.1	47.3	6.64	6.63	0.17	47.78	28.99	3.19	6.68	2.06
1978	38.8	38.8	29.8	15.10	11.34	0	63.92	15.64	4.97	7.78	2.05
1979	51.3	51.3	27.4	21.45	11.73	0	68.29	15.10	5.78	8.46	2.11
1980	67.5	67.5	20.4	21.45	12.19	0	75.35	11.98	6.84	9.08	2.16
1981	88.9	88.9	11.8	21.45	12.19	0	84.00	8.25	8.13	9.68	2.20
1982	117.7	110.4	0	21.45	12.19	0	94.25	2.06	9.37	9.94	2.22
									40.50	Total	

No.: 25 Policy: SIP 1975 NSPS 1975 Parametric Changes: Supply of type 2 LSC increased

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	16.2	16.2	53.4	0.88	0.86	22.40	15.35	54.13	1.15	7.49	3.26
1976	21.2	21.2	78.6	2.72	2.70	12.92	18.59	54.64	1.79	9.63	3.15
1977	34.1	34.1	120.1	6.65	6.64	0	27.66	49.11	3.86	13.96	3.56
1978	46.3	46.3	87.5	15.10	15.08	0	45.70	33.86	6.81	14.90	3.26
1979	63.5	63.5	62.1	33.2	20.24	0	60.21	23.17	9.31	15.46	3.28
1980	87.9	87.9	44.8	33.2	20.51	0	68.96	18.38	10.63	15.41	3.10
1981	122.5	122.5	26.0	33.2	20.51	0	81.66	10.58	13.10	16.04	3.19
1982	172.2	154.8	0	33.2	23.09	0	96.13	0.18	15.99	16.63	3.32
									62.64	Total	

No.: 26 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: Supply of type 2 LSC increased

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	16.2	16.2	56.0	0.88	0.86	2.02	29.51	39.97	1.19	4.03	2.25
1976	21.2	21.2	48.9	2.71	2.69	2.02	34.70	38.53	1.75	5.04	2.16
1977	34.1	34.1	36.4	6.64	6.61	0.17	47.12	29.65	3.48	7.38	2.29
1978	46.3	46.3	8.5	15.05	15.04	0	68.68	10.88	6.28	9.14	3.37
1979	63.5	63.5	0.4	33.1	15.64	0	80.20	3.18	7.52	9.38	2.28
1980	87.9	83.6	0	33.1	15.94	0	86.49	0.84	9.05	10.46	2.46
1981	122.5	103.0	0	33.1	15.94	0	91.40	0.84	10.14	11.09	2.53
1982	172.1	118.4	0	33.1	17.55	0	95.47	0.84	11.36	11.90	2.65
									50.77	Total	

No.: 27 Policy: SIP 1975 NSPS 1975 Parametric Changes: Supply of FGD decreased

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	98.3	0.88	0.87	8.37	14.78	54.70	0.93	6.29	2.89
1976	17.2	17.2	124.3	1.87	1.82	2.41	17.45	55.78	1.30	7.45	2.56
1977	29.1	29.1	133.0	2.92	2.92	0	24.10	52.67	2.34	9.71	2.67
1978	38.8	38.8	128.9	4.17	4.15	0	28.62	50.94	3.24	11.32	2.80
1979	51.3	51.3	123.2	5.56	5.53	0	34.64	48.75	4.18	12.07	2.76
1980	67.5	67.5	116.2	7.13	7.12	0	41.14	46.20	5.55	13.49	2.85
1981	88.9	88.9	101.7	8.93	8.87	0	50.85	41.39	7.56	14.87	2.96
1982	117.7	117.7	71.4	10.89	10.86	0	65.31	31.00	10.14	15.52	2.98
									35.24	Total	

No.: 28 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: Supply of FGD decreased

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	53.3	0.88	0.86	2.02	28.79	40.69	0.88	3.06	1.84
1976	17.2	17.2	55.2	1.85	1.83	2.02	31.73	41.50	1.25	3.94	1.96
1977	29.1	29.1	62.7	2.94	2.92	0.17	38.71	38.06	2.44	6.30	2.28
1978	38.8	38.8	57.2	4.18	4.18	0.17	47.55	32.01	3.19	6.71	2.08
1979	51.3	51.3	52.1	5.62	5.60	0.17	52.92	30.47	4.20	7.94	2.24
1980	67.5	67.5	41.4	7.24	7.23	0	64.28	23.05	5.56	8.65	2.17
1981	88.9	88.9	23.8	9.10	9.08	0	75.74	16.51	7.34	9.56	2.25
1982	117.7	117.7	0.45	11.21	9.12	0	93.91	2.40	9.27	9.87	2.20
									34.03	Total	

No.: 29 Policy: SIP 1977 NSPS 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	143.7	0.88	0.87	0	17.81	58.96	1.38	7.75	2.65
1978	30.2	30.2	136.1	2.74	2.74	0	23.28	56.28	2.31	9.92	2.73
1979	40.6	40.6	121.4	6.74	6.66	0	31.05	52.33	4.05	13.04	2.98
1980	54.1	54.1	88.4	15.11	15.06	0	46.63	40.71	7.24	15.53	3.23
1981	72.2	72.2	73.3	33.1	19.42	0	63.11	29.14	9.73	15.42	3.11
1982	96.8	96.8	59.0	33.1	19.44	0	74.05	22.26	11.45	15.46	3.08
									36.16	Total	

No.: 30 Policy: SIP 1980 NSPS 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	21.9	0.6	0.88	0	0	76.61	0.16	1.00	1.30	2.24
1978	30.2	29.4	0	0.88	0	0	79.56	0	1.28	1.61	2.06
1979	40.6	39.9	0	0.88	0	0	83.39	0	1.72	2.06	2.00
1980	54.1	54.1	143.2	0.88	0.87	0	29.33	58.01	2.91	9.92	2.33
1981	72.2	72.2	137.0	2.74	2.73	0	38.62	53.63	4.72	12.22	2.60
1982	96.8	96.8	108.4	6.74	6.70	0	52.46	43.85	7.59	14.47	2.87
									19.22	Total	

No.: 31 Policy: 1.21 lb SO_2/MBtu 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	185.0	0.88	0.87	0	9.09	67.68	1.37	15.07	2.65
1978	30.2	30.2	176.8	2.75	2.75	0	14.12	65.45	2.35	16.64	2.79
1979	40.6	40.5	163.1	6.79	6.78	0	22.02	61.37	3.93	17.85	2.95
1980	54.1	54.1	129.9	15.44	15.43	0	37.13	50.21	7.32	19.71	3.30
1981	72.1	72.1	119.0	34.04	17.55	0	46.75	45.50	9.22	19.72	3.32
1982	96.8	96.8	114.6	34.04	17.58	0	56.39	39.92	11.09	19.67	3.32
									35.28	Total	

No.: 32 Policy: 1.50 lb SO_2/MBtu 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	190.8	0.88	0.86	0.17	9.69	67.07	1.39	14.34	2.52
1978	30.2	30.2	184.0	2.69	2.68	0.37	14.27	65.29	2.27	15.91	2.70
1979	40.6	40.6	169.1	6.59	6.52	0.48	22.68	60.70	4.08	17.99	2.94
1980	54.1	54.1	133.2	14.77	14.74	0.48	39.14	48.19	7.14	18.24	3.07
1981	72.2	72.2	112.8	32.41	18.32	0	51.50	40.74	9.67	18.78	3.17
1982	96.8	96.8	94.2	32.41	18.34	0	62.19	34.12	11.21	18.02	3.10
									35.76	Total	

No.: 33 Policy: 2.0 lb SO_2/MBtu 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	151.6	0.88	0.84	1.45	11.34	65.44	1.35	11.90	2.24
1978	30.2	30.2	148.6	2.65	2.65	0.47	16.63	62.93	2.33	14.01	2.49
1979	40.6	40.5	132.1	6.55	6.51	0.57	25.63	57.76	4.22	16.46	2.78
1980	54.1	54.0	98.3	14.80	14.79	0	45.14	42.20	7.41	16.42	2.82
1981	72.2	72.2	81.1	32.59	17.46	0	58.04	34.20	9.50	16.37	2.88
1982	96.8	96.8	60.2	32.59	17.48	0	70.83	25.48	11.09	15.66	2.77
									35.90	Total	

No.: 34 Policy: 2.5 lb SO_2/MBtu Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	123.5	0.88	0.87	0.71	14.11	62.66	1.41	9.99	2.11
1978	30.2	30.2	114.8	2.73	2.73	0.78	19.91	59.65	2.44	12.26	2.38
1979	40.6	40.6	96.8	6.73	6.72	0.86	31.11	52.27	4.29	13.79	2.50
1980	54.1	54.1	62.5	15.31	15.30	0.38	51.71	35.63	7.56	14.62	2.70
1981	72.2	72.2	31.6	33.74	21.38	0.03	76.20	16.05	10.64	13.96	2.55
1982	96.8	96.8	9.2	34.47	21.40	0	90.67	5.64	12.29	13.55	2.47
									37.63	Total	

No.: 35 Policy: 3.0 lb SO_2/MBtu 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	97.3	0.88	0.87	0.25	19.98	56.79	1.43	7.16	1.91
1978	30.2	30.2	87.1	2.73	2.73	0.39	26.93	52.63	2.57	9.54	2.20
1979	40.6	40.6	69.1	6.73	6.72	0.46	40.05	43.34	4.34	10.84	2.25
1980	54.1	54.1	31.9	15.31	15.27	0.23	64.79	22.54	7.61	11.74	2.31
1981	72.2	72.2	8.9	33.64	18.53	0	86.57	5.68	10.00	11.55	2.26
1982	96.8	87.3	0	33.64	18.53	0	96.31	0	11.17	11.60	2.27
									37.12	Total	

No.: 36 Policy: 3.5 lb SO_2/MBtu 1977 Parametric Changes: None

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	72.8	0.88	0.88	0.26	22.18	54.59	1.72	7.75	2.04
1978	30.2	30.2	60.4	2.76	2.76	0.38	30.09	49.47	2.71	9.01	2.09
1979	40.6	40.6	41.1	6.80	6.79	0.44	47.77	35.62	4.54	9.50	2.01
1980	54.1	54.1	9.3	15.47	13.37	0	80.79	6.54	7.49	9.27	1.87
1981	72.2	69.4	0	27.52	13.37	0	92.24	0	8.63	9.36	1.87
1982	96.8	77.8	0	27.52	13.38	0	96.31	0	9.24	9.59	1.89
									34.33	Total	

No.: 37 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost raised 10% 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	49.41	0.88	0.87	8.76	29.07	47.70	1.66	5.71	2.91
1978	30.3	30.3	42.65	2.74	2.74	8.52	35.94	43.62	2.70	7.51	2.72
1979	40.6	40.6	31.4	6.76	6.74	8.37	44.54	38.85	4.62	10.37	3.06
1980	54.1	54.1	19.40	15.35	15.33	4.04	62.31	25.02	8.38	13.45	3.30
1981	72.2	72.2	3.33	33.80	21.94	0	89.94	2.30	12.06	13.41	3.01
1982	96.8	87.62	0	36.13	21.94	0	95.47	.84	13.52	14.16	3.12
									42.94	Total	

No.: 38 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost raised 15% 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	35.8	0.88	0.86	12.72	28.73	48.05	1.79	6.23	3.41
1978	30.3	30.3	36.0	2.71	2.69	10.59	36.43	43.14	2.90	7.96	2.98
1979	40.6	40.6	28.6	6.62	6.61	9.35	44.61	38.77	4.93	11.05	3.32
1980	54.1	54.1	12.71	15.04	15.03	6.53	61.05	26.28	8.72	14.28	3.52
1981	72.2	72.1	0.19	33.12	23.10	0	91.21	1.03	12.97	14.22	3.19
1982	96.8	85.6	0	40.43	23.10	0	95.65	0.66	14.41	15.06	3.32
									45.72	Total	

No.: 39 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost raised 20% 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	32.0	0.88	0.86	14.11	28.73	48.05	1.96	6.82	3.73
1978	30.3	30.3	32.8	2.71	2.70	13.20	34.86	44.71	3.31	9.50	3.59
1979	40.6	40.6	24.9	6.66	6.65	11.88	43.73	39.65	5.71	13.06	3.91
1980	54.1	54.1	15.72	15.15	15.15	5.40	61.33	26.01	9.71	15.83	3.89
1981	72.2	62.02	0	33.41	27.32	0	91.59	0.66	14.13	15.43	3.47
1982	96.8	72.3	0	53.48	28.32	0	95.65	0.66	15.64	16.35	3.60
									50.46	Total	

No.: 40 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost raised 25% 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	17.29	0.88	0.86	18.14	28.73	48.05	2.13	7.41	4.05
1978	30.3	30.3	15.9	2.71	2.70	18.12	34.86	44.71	3.54	10.15	3.84
1979	40.6	34.1	0.7	6.65	6.65	21.86	44.02	39.37	5.02	11.40	3.62
1980	54.1	54.1	8.8	15.13	15.12	6.49	63.26	24.07	10.05	15.89	4.00
1981	72.2	57.4	0	33.36	29.39	0	91.59	.66	14.40	15.72	3.53
1982	96.8	67.2	0	60.05	30.58	0	95.65	.66	16.04	16.77	3.69
									51.18	Total	

No.: 41 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost raised 30% 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	4.7	0.88	0.86	27.7	28.72	48.05	2.40	8.36	4.44
1978	30.3	30.3	4.1	2.72	2.72	21.9	33.88	45.69	3.83	11.30	4.51
1979	40.6	40.6	7.51	6.71	6.70	16.9	44.03	39.36	6.25	14.19	4.16
1980	54.1	37.9	0.7	15.27	15.25	14.60	54.28	33.06	8.81	16.23	4.02
1981	72.2	43.6	0	33.63	33.63	0.1	88.89	3.36	14.08	15.84	3.60
1982	96.8	58.2	0	73.13	34.76	0	95.65	0.66	16.58	17.33	3.82
									51.95	Total	

No.: 42 Policy: NSPS 1977 NAAQS 1977 Parametric Changes: 50% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	81.8	0.88	0.86	0.42	28.73	48.05	1.29	4.49	2.44
1978	30.3	30.3	75.1	2.71	2.67	0.21	36.43	43.14	2.13	5.85	2.20
1979	40.6	40.6	63.2	6.62	6.61	0.17	44.88	38.51	3.90	8.69	2.58
1980	54.1	54.1	29.8	15.04	15.02	0.03	62.56	24.78	7.07	11.30	2.78
1981	72.2	72.2	0	33.11	23.81	0	91.41	0.84	11.52	12.60	2.83
1982	96.8	84.1	0	42.72	23.81	0	95.65	0.66	12.23	12.79	2.81
									38.14	Total	

No.: 43 Policy:

NAAQS	Urban	1977
IC	Rural	1977
NAAQS	Rural	1980
NSPS		1977

Parametric Changes: 50% cost difference in assignement

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	41.0	0.88	0.87	0.03	50.05	26.72	1.30	2.60	2.34
1978	30.2	30.2	32.7	2.74	2.72	0.03	57.17	22.39	2.11	3.69	2.24
1979	40.6	40.6	20.0	6.69	6.66	0.03	65.78	17.60	3.62	5.50	2.54
1980	54.1	54.1	28.8	15.15	15.13	0.03	62.99	24.34	7.00	11.11	2.83
1981	72.2	72.2	0.03	33.3	21.63	0	91.41	0.84	10.53	11.52	2.66
1982	96.8	84.1	0	35.6	21.63	0	95.65	0.66	11.20	11.71	2.64
									35.76 Total		

No.: 44 Policy: NAAQS Urban 1977; IC Rural 1977; NAAQS Rural 1980; NSPS 1977

Parametric Changes: 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	39.9	0.88	0.07	0	49.93	26.84	1.06	2.12	1.92
1978	30.2	30.2	38.5	0.88	0.07	0	56.34	23.22	1.35	2.40	1.50
1979	40.6	40.6	38.7	0.88	0.07	0	57.25	26.13	1.84	3.21	1.86
1980	54.1	54.1	76.6	0.88	0.07	0	41.58	45.75	2.52	6.06	1.96
1981	72.2	72.2	71.0	0.88	0.07	0	48.47	43.77	3.60	7.43	2.08
1982	96.8	98.8	51.6	0.88	0.07	0	60.60	35.71	5.37	8.86	2.21
									15.74 Total		

No.: 45 Policy: NAAQS Urban 1977; IC Rural 1977; NAAQS Rural 1980; NSPS 1977 Parametric Changes: 0% cost difference in assignment; system reliability cost deleted

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	19.0	0.88	0.78	5.15	52.68	24.09	0.97	1.84	1.45
1978	30.2	30.2	22.0	2.47	2.43	2.57	59.92	19.64	1.50	2.50	1.37
1979	40.6	40.5	22.2	5.96	5.00	0	65.53	17.86	2.28	3.48	1.60
1980	54.1	54.1	39.8	10.54	10.32	0	59.44	27.89	4.05	6.81	1.76
1981	72.2	72.2	31.2	21.76	10.89	0	66.91	25.34	5.05	7.54	1.82
1982	96.8	96.8	13.8	21.76	10.89	0	80.74	15.57	6.26	7.75	1.78
									20.11	Total	

No.: 46 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	79.5	0.88	0.42	0	30.15	46.62	1.19	3.95	1.80
1978	30.3	30.3	78.6	1.31	0.42	0	33.36	46.20	1.48	4.44	1.72
1979	40.6	40.6	80.2	1.31	0.42	0	37.05	46.34	1.96	5.29	1.77
1980	54.1	54.1	77.7	1.31	0.60	0	41.86	45.47	2.69	6.43	1.90
1981	72.2	72.2	78.7	1.31	0.60	0	48.19	44.06	4.01	8.32	2.18
1982	96.8	96.8	60.1	1.31	0.40	0	59.44	36.87	5.60	9.42	2.24
									16.93	Total	

No.: 47   Policy: SIP 1975   NSPS 1975   Parametric Changes: 50% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	99.2	0.88	0.88	8.37	14.58	54.90	0.94	6.45	3.02
1976	17.2	17.2	121.3	2.77	2.75	2.41	17.28	55.95	1.63	9.43	3.20
1977	29.1	29.1	122.0	6.78	6.78	0	26.94	49.83	3.58	13.29	3.45
1978	38.8	38.8	88.7	15.43	15.42	0	39.07	40.49	6.58	16.84	3.70
1979	51.3	51.3	26.9	34.00	34.00	0	67.91	15.48	12.42	18.29	3.77
1980	67.5	67.5	0.3	73.94	40.42	0	87.05	0.28	16.14	18.54	3.83
1981	88.9	83.5	0	73.94	40.43	0	92.24	0	17.43	18.90	3.83
1982	109.5	97.3	0	73.94	40.44	0	96.31	0	18.57	19.29	3.85
									77.29	Total	

No.: 48 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: 10% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	77.17	0.88	0.88	0.19	31.37	45.40	1.31	4.18	1.90
1978	30.3	30.3	68.91	2.76	2.76	0.19	38.01	41.56	2.18	5.74	1.98
1979	40.6	40.6	56.2	6.81	6.79	0.2	48.73	34.65	3.76	7.72	2.16
1980	54.1	54.1	37.7	15.47	11.32	0	66.23	21.10	5.71	8.62	2.12
1981	72.2	72.2	38.5	21.06	11.36	0	72.90	19.35	7.14	9.79	2.28
1982	96.8	96.8	19.01	21.06	11.36	0	84.11	12.20	8.74	10.39	2.29
									28.84	Total	

No.: 49 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: Supply of LSC type 2 increased

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	27.2	27.2	72.3	0.88	0.86	0.17	32.65	44.12	1.61	4.93	2.06
1978	37.8	37.8	69.2	2.70	2.69	0.21	39.03	40.54	2.72	6.97	2.42
1979	52.8	52.8	51.8	6.62	6.60	0.21	49.65	33.73	4.66	9.38	2.64
1980	74.5	74.5	12.0	15.03	14.46	0	78.82	8.51	8.10	10.28	2.38
1981	105.7	100.9	0	31.3	14.46	0	90.18	2.06	9.76	10.82	2.44
1982	151.1	118.1	0	31.3	15.73	0	94.25	2.06	11.18	11.86	2.62
									38.03	Total	

No.: 50 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost increased 5%, 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	22.2	64.3	0.88	0.87	3.15	31.41	43.37	1.51	4.81	2.03
1978	30.2	30.2	63.4	2.74	2.72	1.30	38.30	41.26	2.27	5.93	1.99
1979	40.6	40.6	65.0	6.70	4.02	0	48.51	34.88	3.20	6.60	1.86
1980	54.1	54.1	64.5	6.80	5.34	0	55.17	32.16	4.72	8.56	2.22
1981	72.2	72.2	56.0	8.20	5.92	0	62.73	29.51	6.23	9.93	2.38
1982	96.8	96.8	38.7	8.20	5.91	0	72.68	23.63	8.26	11.36	2.55
									26.19	Total	

No.: 51 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost increased 40% 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	8.6	0	0.88	0.86	29.53	24.20	52.58	0.84	3.47	3.78
1978	24.2	13.1	0	2.71	2.70	28.99	28.39	51.17	1.74	6.13	3.56
1979	29.2	16.4	0	6.67	6.66	27.96	34.39	49.00	3.19	9.26	3.54
1980	35.1	20.0	0	15.18	15.18	20.49	45.06	42.28	6.23	13.82	3.96
1981	41.8	25.6	0	33.48	33.46	5.49	72.63	19.61	12.51	17.22	4.04
1982	49.8	32.0	0	72.78	41.13	0	93.80	2.50	16.23	17.30	3.83
									40.74	Total	

No.: 52 Policy: NAAQS 1977 NSPS 1977 Parametric Changes: LSC annual cost increased 35%; 0% cost difference in assignment

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	22.2	11.8	0	0.88	0.86	28.64	25.25	51.52	1.06	4.20	3.67
1978	26.7	18.5	0	2.71	2.70	27.50	30.04	49.52	2.15	7.16	3.65
1979	32.4	25.1	0	6.67	6.67	25.60	36.94	46.44	3.88	10.50	3.65
1980	39.0	31.7	0	15.18	15.18	17.31	49.76	37.58	7.25	14.57	4.00
1981	46.8	38.1	0	33.47	33.46	2.10	82.91	9.33	13.56	16.36	3.73
1982	56.0	43.4	0	72.79	38.02	0	93.80	2.50	16.10	17.16	3.80
									44.00	Total	

No.: 53 Policy: SIP 1975 NSPS 1975 Parametric Changes: System cost reflects 0.05 increase in F.O.R. for FGD

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	97.1	0.88	0.86	10.37	14.57	54.91	0.88	6.04	2.85
1976	17.2	17.2	116.9	2.73	2.72	3.72	17.64	55.60	1,48	8,39	2.88
1977	29.1	29.1	102.5	6.70	6.70	3.72	27.83	48.94	3.34	12,00	2.98
1978	38.8	38.8	84.5	15.26	15.26	0.19	42.20	37.36	5.84	13.84	2.97
1979	51.3	51.3	48.2	33.66	25.52	0	63.25	20.13	9.24	14.61	3.04
1980	67.5	67.5	44.8	47.57	26.50	0	69.73	17.60	10.46	15.00	3.04
1981	88.9	88.9	36.2	47.57	26.50	0	77.28	14.97	11.88	15.37	3.03
1982	117.7	117.7	14.5	47.57	26.52	0	89.77	6.54	13.81	15.38	3.03
									56.93	Total	

No.: 54 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: System cost reflects 0.05 increase in F.O.R. for FGD

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	49.7	0.88	0.86	4.46	28.79	40.69	0.86	2.99	1.80
1976	17.2	17.2	50.0	2.71	2.70	4.06	33.04	40.20	1.32	4.00	1.88
1977	29.1	29.1	41.0	6.64	6.63	3.47	42.48	34.29	3.18	7.48	2.52
1978	38.8	38.8	22.1	15.09	15.07	0.03	62.17	17.39	5.62	9.04	2.40
1979	51.3	51.3	12.6	33.22	17.48	0	77.30	6.08	7.03	9.09	2.21
1980	67.5	67.5	5.5	33.22	17.94	0	84.32	3.01	8.09	9.59	2.26
1981	88.9	86.9	0	33.22	17.94	0	91.40	0.84	9.27	10.14	2.31
1982	114.7	100.8	0	33.22	17.94	0	95.47	0.84	10.09	10.57	2.35
									45.46	Total	

No.: 55 Policy: SIP 1975 NSPS 1975 Parametric Changes: System cost reflects 0.00 increase in F.O.R. for FGD

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 \$	\$/kw	mills/kw-hr
1975	13.2	13.2	80.8	0.88	0.86	13.44	14.57	54.91	0.86	5.90	2.78
1976	17.2	17.2	88.6	2.73	2.72	11.37	17.64	55.60	1.41	7.99	2.75
1977	29.1	29.1	85.2	6.70	6.70	8.64	27.83	48.94	3.17	11.39	2.83
1978	38.8	38.8	79.1	15.26	15.24	2.19	41.62	37.94	5.43	13.05	2.84
1979	51.3	51.3	33.5	33.60	30.59	0	69.42	13.96	9.52	13.71	2.89
1980	67.5	67.5	27.4	63.60	32.03	0	76.95	10.39	10.99	14.28	2.94
1981	88.9	88.9	18.8	63.60	32.04	0	84.41	7.83	12.34	14.62	2.92
1982	117.7	115.8	0	63.60	32.04	0	96.13	0.18	14.30	14.88	2.97
									58.02	Total	

No.: 56 Policy: NAAQS 1975 NSPS 1975 Parametric Changes: System cost reflects 0.0 increase in F.O.R. for FGD

	LSC (10^6 Tons)			FGD (10^3 Mw)			Response (10^3 Mw)		Annual Compliance Cost		
	Supply	Utilization	Excess Demand at Least Cost	Supply	Utilization	Excess Demand at Least Cost	Compliance	Non-Compliance	10^8 $	$/kw	mills/kw-hr
1975	13.2	13.2	38.4	0.88	0.86	7.34	28.79	40.69	0.84	2.92	1.76
1976	17.2	17.2	41.0	2.71	2.68	6.72	32.56	40.68	1.41	4.33	2.07
1977	29.1	29.1	35.3	6.61	6.60	5.07	43.46	33.32	3.14	7.22	2.37
1978	38.8	38.8	17.3	15.02	15.02	1.22	59.47	20.09	5.38	9.05	2.42
1979	51.3	51.3	3.1	33.11	19.88	0	80.82	2.56	7.28	9.01	2.18
1980	67.5	65.2	0	33.11	20.20	0	86.49	0.84	8.16	9.43	2.21
1981	85.5	81.0	0	33.11	20.22	0	91.40	0.84	9.11	9.97	2.27
1982	105.9	94.9	0	33.11	20.22	0	95.47	0.84	9.93	10.40	2.32
									45.25	Total	